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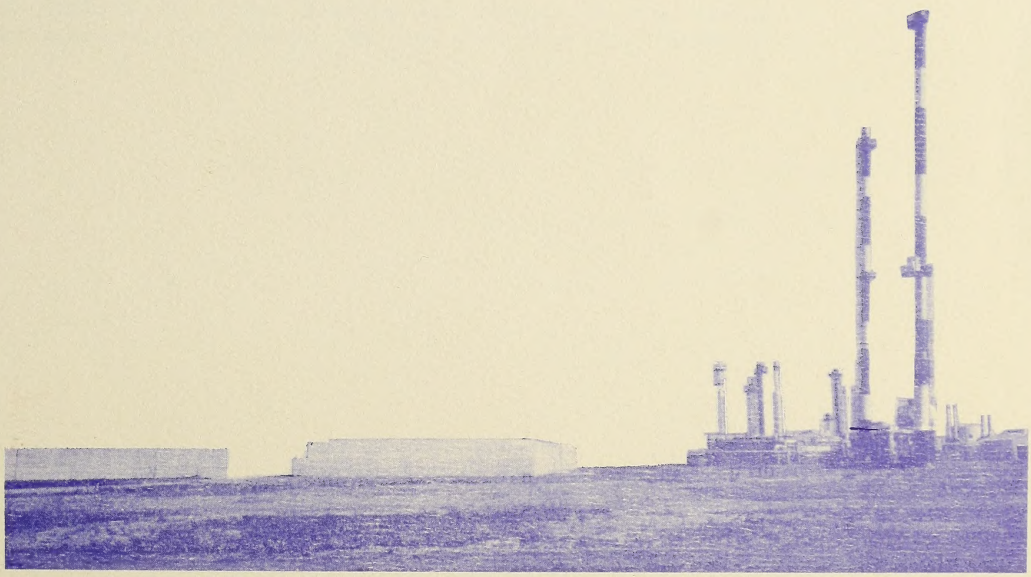
Sulphur Recovery at Alberta Gas Plants

Phase 1 of a Review of the Guidelines

Task Force Report



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Sulphur Recovery at Alberta Gas Plants
Phase 1 of a Review of the Guidelines
Task Force Report

This report has been prepared by staff of Alberta Environment and the Energy Resources Conservation Board, to be used as a working document in a formal multi-stage review of Alberta's sulphur recovery guidelines for gas plants. The review process is described in Appendix A. The report has not been reviewed by senior members of either Alberta Environment or the Energy Resources Conservation Board, as of the date of issuance.

by staff of

Alberta ENVIRONMENT

ERCB

SULPHUR RECOVERY AT ALBERTA GAS PLANTS
PHASE I OF A REVIEW OF THE GUIDELINES
TASK FORCE REPORT

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This report was prepared by

B. Hubbard, P.Eng. - ERCB
K. Johnston - ERCB
C. S. Liu, P.Eng. - Alberta Environment
W. Schnitzler, P.Eng. - ERCB

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Of course any technical and judgemental errors remain those of the authors.

LIST OF ABBREVIATIONS

GEMM - Gas Energy Management Model

EPA - Environmental Protection Agency

PSD - Prevention of Significant Deterioration

NSPS - New Source Performance Standards

BACT - Best Available Control Technology

LAER - Lowest Achievable Emission Rate

BAT - Best Available Technology

TACB - Texas Air Control Board

MAPCC - Michigan Air Pollution Control Commission

SULPHUR RECOVERY AT ALBERTA GAS PLANTS
PHASE I OF A REVIEW OF THE GUIDELINES
TASK FORCE REPORT

1 INTRODUCTION

This report has been prepared by staff of the Energy Resources Conservation Board (ERCB) and Alberta Environment (AE) as part of a formal review of the sulphur recovery requirements for Alberta's sour gas processing plants. The review process involves the industry, special interest groups, and representatives of the public at large. Appendix A sets out the objective of the review, the process to be used, the steps to be taken, and the task force's terms of reference.

Broadly, the review focuses on the technology and economics of sulphur recovery. The subject of impacts of emissions from sour gas plants is not dealt with, being considered a separate issue related more to air quality standards, plant siting, interrelationships between various emitting sources and sensitivity of receptors. There have been studies completed such as The Southwestern Alberta Medical Diagnostic Review - June 1986 and there are currently studies under way such as the Acid Deposition Research Program which address these types of issues.

The remainder of this introductory section provides some background to the evolution of sulphur recovery guidelines in Alberta, information on Alberta's past sulphur dioxide (SO_2) emission rates and actual overall sulphur recovery efficiencies, and a baseline forecast of emission rates.

1.1 Background to Previous Sulphur Recovery Guidelines in Alberta

The Early Period

Major Alberta sour gas production began in the 1930s at Turner Valley, south of Calgary. The recovery of sulphur from sour gas commenced at 2 Alberta plants in the early 1950s, and during the 1960s it expanded into an important industry along with the development of distant markets for Alberta gas. During this period the sulphur recovery requirements at gas plants were prescribed on an individual plant basis by the ERCB in liaison with the Alberta Department of Health. These requirements emphasized the economical meeting of ground level air quality standards, which resulted in plants with tall incinerator stacks and relatively modest sulphur extraction facilities. Sulphur

recovery efficiencies ranged from less than 90 per cent for some small plants to 93 to 98 per cent for the largest plants of more than 1000 tonnes per day (t/d) sulphur inlet capacity.

Sulphur emissions from Alberta gas plants peaked at about 290 000 tonnes in 1972. (This equates to about 800 t/d.)

The 1970s

In 1971, following completion of an in-house study, the ERCB issued guidelines for the sulphur recovery efficiencies at both proposed and existing gas plants. These guidelines specified different recovery requirements depending upon the size of the plant and quality of acid gas feed to the sulphur plant as indicated by the hydrogen sulphide (H_2S) and carbon dioxide (CO_2) contents. The study upon which these guidelines were based reflected the highest recovery of sulphur which could be justified on an economic basis (dollars per incremental tonne of sulphur) having regard for the technologies then available, although recovery in the lower part of the size range could probably not be justified on the basis of sulphur revenues alone. The 1971 guidelines were immediately applied to new plants, and applied to existing plants over a period of 2 or 3 years to allow time for upgrading. A very few older plants were exempted from the requirement to upgrade on the basis of a short remaining life due to declining reserves.

Following implementation of the 1971 guidelines, sulphur emissions from gas plants declined to about 180 000 tonnes per year in the period 1976 to 1980 before rising again due to increasing gas production in the province. A modest slump in sour gas production rates in the years 1974 to 1978 had also contributed to the reduction in sulphur emissions in the period. During the 1970s the average sulphur recovery at plants with sulphur recovery equipment increased from 90 to 97 per cent.

1.2 The 1980 Guidelines

During the 1970s, Environment Canada formed a task force with representatives from the sour gas industry and governments to consider the need for higher standards of sulphur recovery at Canadian gas plants. Total agreement was not reached and negotiations continued. In 1980, a guideline for new plants was proposed which was acceptable to Environment Canada, the sour gas industry and government agencies in Alberta. This guideline was presented in IL 80-24, which was reviewed and agreed to by the parties and signed by AE and the ERCB in December 1980. The guideline is included in this report as Appendix B.

Because the 1980 agreement was reached by negotiation between parties, it is not possible to state a rationale for it apart from the governments' wish to reduce emissions and the willingness of the industry to accept the cost burden associated with the higher recovery levels for new plants.

IL 80-24 is currently applied by AE and the ERCB to all new sour gas plants. Being a guideline, some deviation from it (usually in the direction of increased recovery of sulphur) has been exercised where local circumstances have been recognized or the technology available to meet the guideline permits the setting of a greater recovery efficiency. It is important to note that the guideline is applied on a quarterly basis, ensuring conformance over long periods of time. (Some jurisdictions have guidelines setting a "normal operating basis" requirement with provision to operate below the prescribed level at times when plant performance is not up to par.) IL 80-24 is applied on a judgemental basis to plants which are being modified or expanded, or are taking on new sour gas streams. Depending on the circumstances, such as the relative amount of H_2S coming from new sources, the sulphur recovery requirement may be increased.

One significant difference between the 1980 and 1971 guidelines is that the variance in recovery level dependent upon acid gas quality has essentially been eliminated in the 1980 guideline.

1.3 Historical Sulphur Emissions from Alberta Gas Plants

The relationship between gas production, sulphur emissions, and sulphur recovery efficiency for the Alberta gas processing industry over the period from 1961 to 1985 is shown on Figure 1-1. Sulphur emissions reached a peak in 1972 of some 800 t/d. While the amount of sulphur handled yearly since 1972 has decreased modestly from about 17 500 t/d to about 14 500 t/d, sulphur emissions have declined markedly from a peak of 800 t/d to about 300 t/d over the same period. This decrease in emissions has occurred largely because of increased levels of sulphur recovery being required and installed at Alberta's plants. The most acute effect of increased recovery levels was seen with the implementation of the 1971 guideline which brought about a sharp decline in what had been, up until then, a rising rate of sulphur emissions. The actual average sulphur recovery efficiency for all of Alberta's plants that recover sulphur increased from 95.7 per cent in 1971 to 97.9 per cent in 1985. If the acid gas flaring plants which recover no sulphur are included, the average for all plants in 1985 is 97.6 per cent.

Figure 1-2 shows the relative contribution of each of 7 ranges of plant sizes to the total 1985 sulphur emission rate. The number of

plants in each group is also shown. For example, the graph shows that 8 plants having approved sulphur inlet rates of 1000 to 5000 t/d emitted approximately 150 t/d of sulphur, some 40 per cent of the total emission. At the other end of the scale, 87 plants having approved inlet rates of less than 1 t/d emitted approximately 20 t/d, contributing about 3 per cent to the total emission.

1.4 Forecast Sulphur Emissions

Our forecast of future sulphur emission rates from Alberta gas plants is shown in Figure 1-3. The forecast covers the period from 1986 to 2010 and shows expected emissions from existing plants, future plants assuming current sulphur recovery requirements, and the total from both groups.

We used the ERCB's Gas Energy Management Model (GEMM) in developing the forecast of emissions. For established reserves GEMM uses reserve size, gas composition, and deliverability data on an individual pool basis. Also, based on the geological potential for gas in the province, it is assumed that new gas pools will be discovered and developed during the forecast period. For these reserves, composition and deliverability characteristics are estimated on a provincial basis. GEMM uses a forecast of demand for Alberta gas in conjunction with this supply data to generate an expected production forecast for gas and gas co-products.

Actual recovery efficiency data is used in calculating emissions for established reserves producing to existing plants. Emissions from the production of new (unconnected at start of forecast period) sour gas reserves either at new or existing plants are calculated on the basis of a 99 per cent average recovery efficiency (the actual average achieved in 1985 was 97.9 per cent but the task force estimates that as the proportion of new plants meeting the minimum requirement of IL 80-24 increases, the weighted average recovery efficiency will approach 99 per cent). Although there is considerable uncertainty respecting such matters as gas demand, tie-in of currently unconnected gas, and amount and sulphur content of gas yet to be discovered, we believe the forecast reasonably represents the base case under existing sulphur recovery guidelines.

It should be recognized that the forecast does not include emissions resulting from the possible processing of ultra-high H_2S gas (greater than about 60 per cent H_2S) known to exist in Alberta. A recent forecast[1] of production of such gas shows two cases: a low case where

---

1 DeSorcy, G.J., 1985. Sulphur Recovered From Oil and Gas in Canada. Energy Resources Conservation Board. Calgary, Alberta.

no ultra-high H_2S gas is produced and a high case where production of such gas begins by 1988 and increases steadily until it would add about 25 per cent to the production and emission figures in the final forecast years.

Some general conclusions can be drawn from the forecast. First, emissions from existing plants are expected to increase slightly through the late 1980s, largely due to forecast increasing demand for Alberta gas. After peaking in the early 1990s, however, emissions from existing plants decline rapidly due to declining deliverability of the reserves feeding these plants. Second, although emissions from future plants are expected to increase through to the end of the century, this increase would be more than offset by the reduction of reserves available to and, hence, the sulphur emissions from the existing plant group. This results in an overall decline in total sulphur emissions starting in the mid-1990s and continuing to the end of the forecast period.

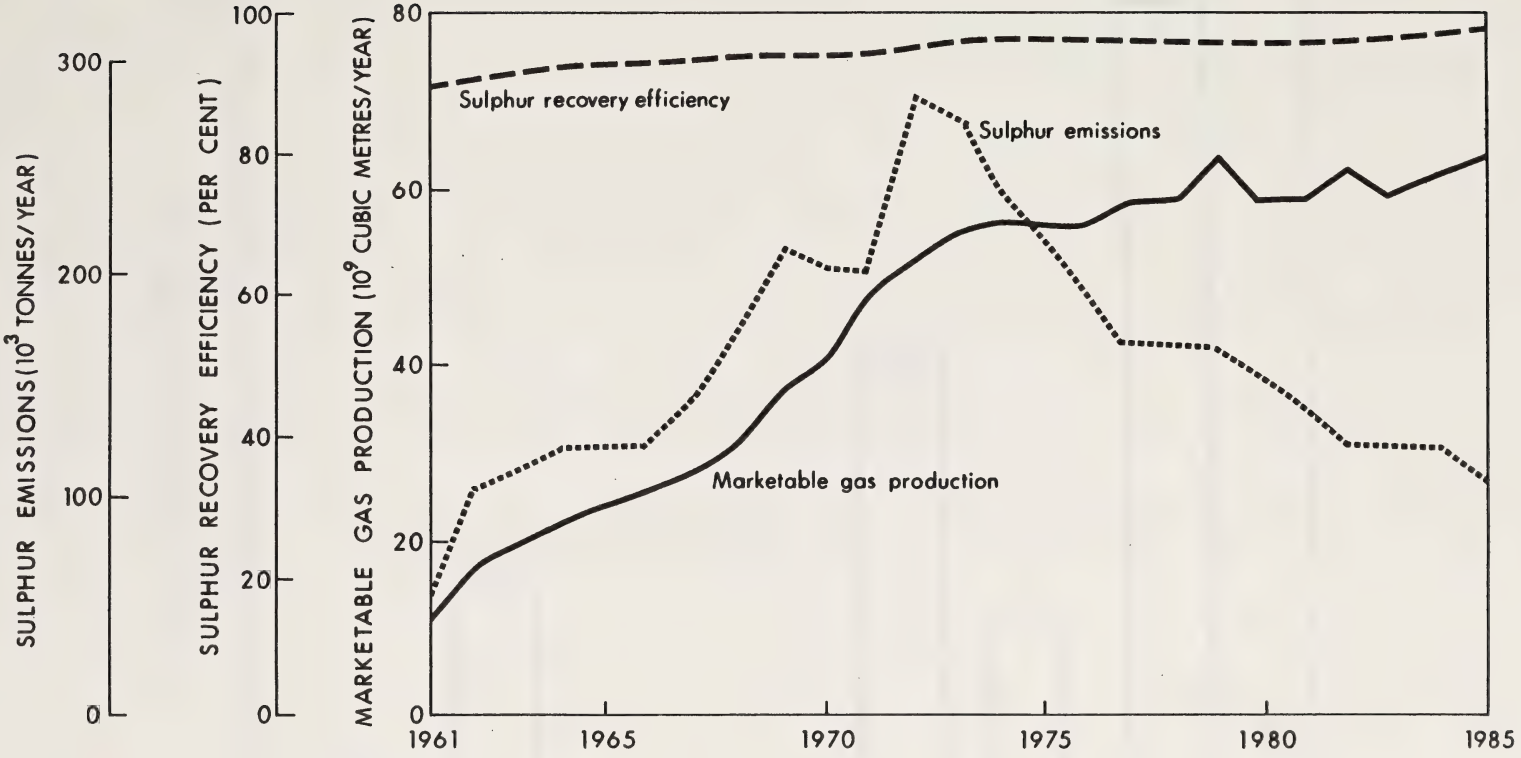

FIGURE 1-1 ALBERTA MARKETABLE GAS PRODUCTION*, SULPHUR EMISSIONS AND RECOVERY FROM SOUR GAS OPERATIONS – 1961 TO 1985

* Total marketable gas production, including that from sweet as well as sour natural gas production

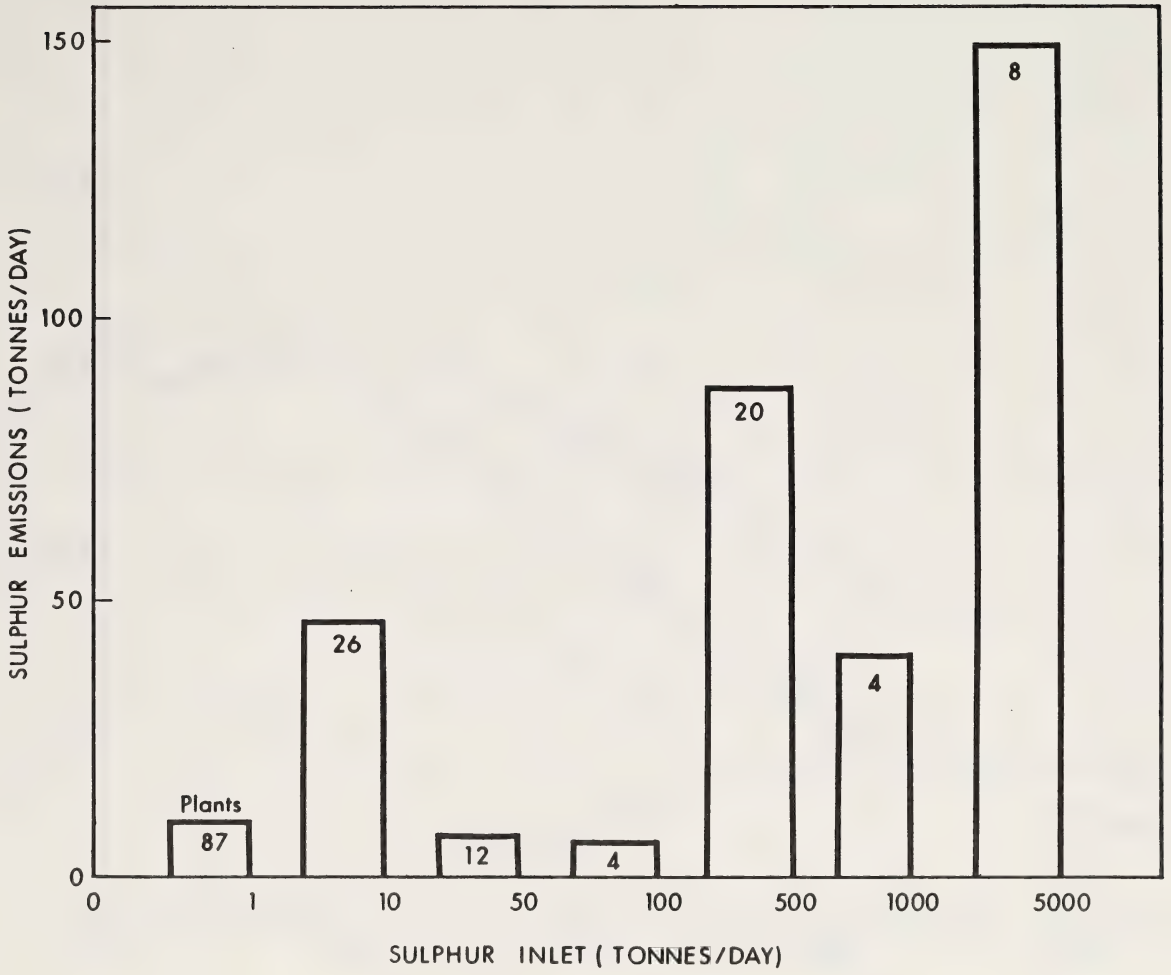

FIGURE 1-2 SULPHUR EMISSION RATES BY PLANT GROUP - 1985

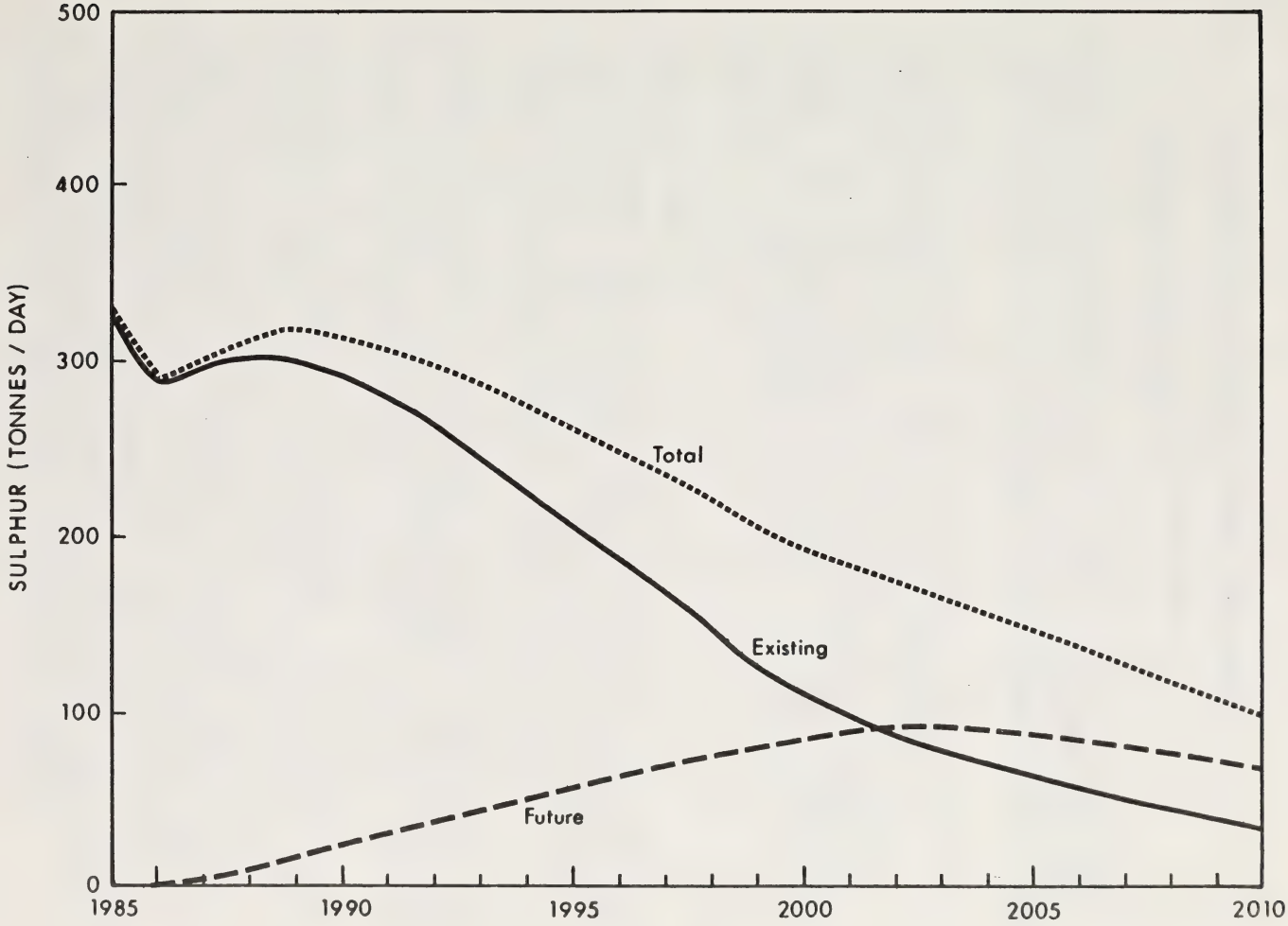

FIGURE 1-3 FORECAST SULPHUR EMISSIONS FOR EXISTING AND FUTURE PLANTS UNDER CURRENT GUIDELINE

2 CONSIDERATION OF EMISSION CONTROL STRATEGIES

2.1 Review of Sulphur Recovery Requirements in Other Jurisdictions

As part of the review process, we canvassed and met with government officials in other jurisdictions where sour gas is processed. The purpose of the survey was to compare Alberta's current requirements with those elsewhere and to determine whether variations exist in the basic strategies of controlling sulphur emissions.

This section summarizes the information obtained through the survey respecting sulphur recovery rules in various North American jursidictions including the Province of British Columbia and the United States Environmental Protection Agency (EPA) and selected states. Selection of jurisdictions to be included was based on the presence of a sour gas processing industry. As well as information regarding the rules and their application, information regarding the number and size of facilities in place was considered to be important.

British Columbia

British Columbia has 3 sour gas plants ranging in size from 467 t/d to 1060 t/d. The sulphur recovery levels set for the plants are 95 per cent for the two smaller plants and 99 per cent for the largest plant. The total maximum approved emissions from the three plants at the recovery levels required would be some 67.5 t/d of sulphur.

The legislation applying to new sour gas processing plants in British Columbia has been in effect since 1974 and suggests an objective of 99 per cent sulphur recovery for plants handling acid gas with an H_2S content of greater than 10 per cent. If the H_2S content is less than 10 per cent the sulphur recovery objective is 95 per cent. We understand these objectives are not viewed by the Ministry of Environment as applicable to all cases; hence, when an application is received, the sulphur recovery level is set after the details of the scheme have been reviewed with the applicant. The objectives are based on all sulphur entering the gas plant; therefore, one would conclude they are meant to include an allowance for flaring. Among the materials received from the Ministry of Environment are some statements referring to relevant aspects for any new guidelines for British Columbia that may be issued in the future. One of these statements suggests an allowance for the recovery level on a monthly or quarterly average basis could be stipulated to accommodate flaring of raw or acid gas during start-up, shut-down, and emergency conditions similar to the 0.3 per cent allowance in Alberta.

United States - Environmental Protection Agency (EPA)

The EPA has established two types of rules which affect the sour gas industry in the United States. In 1977, it established its Prevention of Significant Deterioration (PSD) rules designed to protect ambient air quality in areas where the air quality was good and to reduce the concentrations of criteria pollutants (the criteria pollutants are nitrogen oxides, sulphur dioxide, carbon monoxide, hydrocarbons, and particulate matter) in areas where federal ambient air standards were being exceeded.

In October 1985, the EPA set New Source Performance Standards (NSPS) that are now in full effect for all new on-shore sour gas processing plants. These rules now set out a minimum required level of sulphur recovery for all new plants larger than 2 long tons per day (LT/d).

The NSPS rules are somewhat complex but can be visualized graphically as illustrated in Figure 2-1. The EPA requirements shown are for continuous operation and are somewhat less than the EPA initial requirements which a new plant with fresh catalyst would be required to meet. The EPA requirements for continuous operation can be directly compared to the current Alberta guidelines.

The EPA rules exceed the current Alberta rules at the two extremes of plant sizes. For the small plant sizes we interpret the requirement of sulphur recovery as being significant because the United States has many small plants, and should be expected to see many more such plants built over the next few years. With respect to larger plants (more than 500 t/d) the EPA rules suggest, for example, that a plant handling acid gas containing 60 per cent H_2S would have a higher continuous operating requirement than a similar plant in Alberta. The difference between the EPA and Alberta rules grows from zero at 500 t/d to about .1 per cent at 1500 t/d, then shrinks back to about 0.6 per cent in the more than 2500 t/d range.

The NSPS rules are now viewed as the minimum requirements to be applied in each state. In some states, existing local rules exceed the NSPS requirements as discussed later.

Under the PSD rules, every new source which emits over 250 short tons (ST) per year of a criteria pollutant must obtain a PSD permit. A PSD permit requires the applicant to demonstrate the use of Best Available Control Technology (BACT) to control emissions, to do computer modelling of the emission sources in the area to ascertain the increase in ambient concentrations due to the new source, to address the impact of the source's emissions on visibility, vegetation, and

soils, and to address the impact of population growth due to the source on the air quality. BACT is a case-by-case determination and the cost of the control is used in weighing which type of control equipment is appropriate. In some areas in the United States defined as non-attainment areas, where ambient concentrations of any of the criteria pollutants exceed federal standards, the PSD rules require any new source to use technology that would result in the Lowest Achievable Emission Rate (LAER) as well as propose a plan to show a reduction in emissions from an existing source in the area of at least as much as the proposed emissions from the new source. The sour gas industry would rarely be affected by the non-attainment rules because it typically is not located in or near urban areas with other industrial sources.

The EPA and several of the states refer to BACT, and the reader should be aware that BACT does not mean the same thing as Best Available Technology (BAT) as used in this report. As an example, BACT, even very recently in some states, has been determined by the rule makers to be a considerably lower sulphur recovery level than BAT. Although cost is used in determining BACT, the most important factor is the ambient air impact. For example, if computer modelling shows that a proposed plant is predicted to exceed any allowed increment in air degradation, a higher degree of control would be required, regardless of the cost.

Texas

Since 1977 Texas has approved about 60 new or expanding sour gas plants. About one-quarter of these plants are larger than 2 LT/d; that is, three-quarters of the new plants do not recover sulphur. Of the 15 plants that have been built or modified since 1977, and which have sulphur recovery, the sulphur inlet ranges from 0.1 LT/d to 800 LT/d and the approved efficiencies of these plants range from 94.0 to 99.7 per cent.

The Texas Air Control Board (TACB) administers the sulphur recovery rules for the state. Texas has stated that its strategy for improving air quality is to develop rules that require all new, modified, and replacement facilities to be equipped with the best air pollution control technologies that are practical and economically reasonable. Texas states that over time, natural attrition of older facilities and application of these rules will result in all sources in the state being controlled with the best available control technologies.

The TACB has set "initial positions" on sulphur recovery efficiencies, as shown below, which represent what it has determined to be BACT for plants in the state. An applicant proposing anything less than the

initial positions would be required to demonstrate that the level of sulphur recovery proposed is in fact BACT for its facility. Texas appears to give a lot of weight, however, in its BACT determinations to precedence, so it is unlikely that BACT would be determined to be less than the initial position.

Sulphur Handled[a], LT/d	Minimum Efficiency[b], %
0 to 2	no position
2 to 20	96.0
20 to 50	98.5
>50	99.8

a Sulphur content of inlet stream, 1 long ton = 1.016 tonne.

b These efficiencies do not account for flaring of gas which might occur before the gas gets to the sulphur plant inlet.

In the past, net annualized capital and operating costs were important factors in the TACB determination of BACT. Annualized costs of up to about $1000/t of SO_2 abated (which equates to $2000/t of sulphur abated) have been viewed by the TACB as representing a reasonable level of control technology.

In addition, the degree of sulphur recovery must satisfy federal requirements summarized earlier in this report. It should be noted that the NSPS requirements are less stringent than those administered by the TACB. Our understanding of the situation is that proponents of new sour gas processing schemes will likely apply to the TACB on the assumption that the NSPS requirements represent BACT.

Alabama

There are 10 sour gas plants in Alabama. The size range is from very small (0.01 LT/d to 3.6 LT/d which are limited to emitting 250 ST per year of SO_2) to large (1500 LT/d which is required to recover 99.86 per cent of the sulphur). Approved sulphur emissions from the 10 sour gas plants total approximately 100 LT/d.

In Alabama there are three different sets of regulations under which a sour gas plant could be regulated, depending upon the date it was built and the size of the plant.

The first set of regulations is comprised of rules which are implemented solely by the State of Alabama. The degree of sulphur recovery is dependent upon the county where the plant is located and the acid gas composition. These rules have resulted in recovery efficiencies ranging from 88 to 96 per cent with one 10 LT/d plant being approved with no recovery. These rules were the only regulations which covered natural gas processing plants until the second set of rules, the PSD program, was implemented by the EPA.

Under the PSD program, some examples of recent BACT determinations in Alabama are as follows: a 780 LT/d plant required to recover 99.86 per cent using the SCOT tail gas clean-up process, and a 114 LT/d plant required to recover 98.5 per cent of the available sulphur using a subdewpoint Claus process.

The final set of regulations which affect sour gas processing plants are the federal NSPS referred to earlier. If a plant is subject to both the PSD and NSPS rules, the recovery level must be at least as stringent as the degree of control required by the NSPS rules. However, if an ambient air standard would be violated using the NSPS rules, a higher degree of control would be required.

It should be noted that the implementation of the federal PSD rules which in most cases would require a higher degree of sulphur recovery than Alabama's state rules, and the implementation of the federal NSPS rules which would in every case require a higher level of recovery than the state rules, has essentially made the state rules redundant.

Michigan

Michigan has some 50 natural gas sweetening facilities, all of which would be classified as small plants by Alberta standards with the largest plants processing some 20 LT/d of sulphur. Most of the facilities have sulphur inlet rates of less than 1 LT/d. Six plants recover sulphur from the acid gas at varying recovery levels from 70 to 99.9 per cent. Approved sulphur emissions from sour gas plants totals approximately 25 LT/d.

In 1980, the Michigan Air Pollution Control Commission (MAPCC) promulgated regulations to require the installation of BACT equipment at all new sour gas sweetening facilities. From 1980 to 1982 the new rule was not strictly enforced because of industry's argument that installing control on sources emitting less than 250 ST/year of SO_2 was not feasible. During the same period, the MAPCC became concerned that a number of small plants were being proposed and built in close proximity to one another and near a village. All the plants were smaller than the 250 ST/year cutoff for the PSD rules and as such, no emission control equipment was being proposed. A review of BACT for

small sweetening facilities was then undertaken by the MAPCC. The effect of installing emission control equipment on the total and marginal costs of processing the gas was examined. Michigan continues to use this type of analysis to determine BACT on a case-by-case basis.

Since 1982, a number of sweetening facilities have been approved. Four facilities emitting 250 ST/year of SO_2 or less have been approved with no sulphur recovery. One larger plant at 10 LT/d capacity was approved with 3-stage Claus sulphur recovery, while the largest plant at 20 LT/d was approved to use Lo-Cat, and a number of intermediate size plants (mainly less than 1 LT/d) have been approved with Lo-Cat, caustic scrubbing or Slurrisweet processes, resulting in sulphur recovery levels ranging from 95 to 100 per cent. The majority of the plants operating in Michigan pre-date the state rules and are not required to control SO_2 emissions. It is clear that Michigan's current policy regarding BACT at small plants is more stringent than the federal NSPS rules which do not require sulphur recovery at plants smaller than 2 LT/d. For larger plant sizes, if it had any in the state, the MAPCC believes that its requirements would be similar to the NSPS.

It should also be noted that, in Michigan, companies are able to obtain a tax exemption certificate from the state which exempts them from property taxes and sales taxes on air pollution control equipment installed at their facility. This exemption can, in certain circumstances, greatly improve the economics of installing pollution control equipment.

Wyoming

Wyoming has 16 sour gas plants, 4 of which flare acid gas with the largest flaring some 7.7 LT/d. Sulphur recovery plant capacities range from 6.75 LT/d with 90 per cent recovery up to 1733 LT/d with 99.7 per cent recovery. Approved sulphur emissions from the 16 sour gas plants total approximately 87 LT/d.

The state began permitting sour gas plants in 1974 to ensure that plants would comply with ambient air standards. At that time, attention was not focussed specifically on sulphur recovery levels, if plants were designed to meet ambient standards. In 1977 when the federal PSD rules came into effect, the state began looking at BACT determination for sour gas plants. Also, now the newly promulgated NSPS rules define the base sulphur recovery levels required in the state. For the plants built since 1977, BACT determinations by the state have resulted in the installation of subdewpoint, SCOT, or Stretford tail gas clean-up technology at the larger plants. One 45 LT/d plant was approved with a 3-stage Claus unit without tail gas clean-up and one small plant (0.042 LT/d) was given approval to flare its acid gas.

North Dakota

There are 16 sour gas plants constructed or approved in North Dakota, 8 of which recover sulphur and 8 of which use iron sponge or equivalent or flare acid gas. The sulphur recovery plants range in size from 12 LT/d to 181 LT/d. The largest of the acid gas flaring plants flares some 2.4 LT/d of sulphur. Approved sulphur emissions from the 16 plants total approximately 18 LT/d. The majority of the sour gas production is associated or solution gas produced with oil.

Only 2 sour gas plants operated in North Dakota prior to 1977 and the implementation of the PSD rules and the requirement on these plants was to meet ambient air standards. Since then, the state authority has undertaken a BACT review for all new facilities in accordance with the PSD rule. As with the other states, the new NSPS rules constitute a base recovery level for proposed new facilities.

For BACT determination in North Dakota, the state looks at the incremental cost of abated sulphur emission as the measure of reasonableness of various recovery levels. The cutoff figure used in North Dakota is \$1000/ST SO_2. In other words, if the cost of achieving some incremental abatement of SO_2 emission is less than \$1000/ST it is reasonable for a company to install equipment to do so. For all but one of the sulphur recovery plants, BACT has been determined to be subdewpoint technology that would achieve about 98.6 per cent recovery. One plant which was retrofitted in 1983 with the addition of a 15 LT/d sulphur recovery unit does not have a tail gas clean-up unit. Recently, the state authority has been of the view that subdewpoint technology is capable of 99.2 per cent recovery rather than the 98.6 per cent, so 99.2 per cent will be required as BACT for future plants. However, we believe this higher figure is the design capability of the technology rather than being an indicator of its continuous operating level.

California

The County of Santa Barbara has 3 sour gas processing plants treating up to 20 LT/d of sulphur in the Los Angeles basin. Because of its particular geography and meteorological situation, together with the historically high burdens of pollutants, very stringent rules have developed. Santa Barbara County's rules, for example, allow for a maximum emission rate of 15 pounds per hour of any pollutant, including SO_2. The effect of the rules is that no sour gas plant would be built in the County of Santa Barbara without 99.8 per cent recovery or higher.

New Mexico

Approximately 150 sour gas processing plants operate in New Mexico. A dozen of the plants are sized between 20 and 30 LT/d and recover sulphur. The majority of the remaining plants are sized between 2 and 3 LT/d and flare the acid gas. Sour gas plants emitted approximately 300 ST/year of SO_2 in 1980.

New Mexico implemented sulphur recovery regulations in 1974 which applied to existing as well as new plants. For existing plants larger than 7.5 LT/d, the minimum recovery levels were set at 88 to 90 per cent, depending on acid gas quality. For new plants, the recovery levels were set at 90 per cent for plants sized between 5 and 20 LT/d, 90 to 96 per cent for plants between 20 and 50 LT/d and 98 per cent for plants larger than 50 LT/d.

The majority of the sulphur recovery plants operating in the state were built prior to 1974 and recover approximately 90 per cent of the inlet sulphur.

It should be noted that any new plants proposed for New Mexico would also be subject to federal PSD and NSPS rules.

Other

An inquiry was sent to the French Ministere de l'Environnement regarding sulphur recovery rules in France but no response was received. From discussions with a representative of Societe Nationale Elf Aquitaine (SNEA) we understand that France does not require sulphur recovery levels any higher than that attainable by SNEA-developed processes such as Sulfreen. We understand this situation applies to other countries such as the U.S.S.R. where engineering firms have been hired to install sulphur recovery facilities; that is, the degree of sulphur recovery required likely corresponds to the capability of equipment proposed in the winning bid for the overall project.

Conclusions

We conclude the following from our survey of other jurisdictions:

- The federal PSD rules are administered in every state. Under these rules, all new sour gas sweetening plants that would emit more than 250 ST/year of SO_2 and sulphur recovery plants that would emit more than 100 ST/year of SO_2 must demonstrate that BACT is being applied and that the proposed facility would not increase the ambient SO_2 concentration in the area by more than an allowed increment.

- The newly implemented federal NSPS applies to all states and represents the minimum levels of sulphur recovery that must be applied. Sulphur recovery levels required under the NSPS for continued operation are roughly equivalent to Alberta's current requirements for plants in the 10 to 500 t/d size range. The NSPS requirements are more stringent than Alberta's for plants in the 2 to 10 t/d category and for plants larger than 500 t/d.

- For plants approved under the federal PSD rule, it appears that in most cases, sulphur recovery levels set by BACT determinations have been somewhat higher than would be required under Alberta's current requirements. It should be noted that calculated marginal cost figures in the order of $2000/t of abated sulphur emission appear to be a commonly used cutoff in BACT determinations.

- In some states, sulphur recovery units have been designed and approved over the past 5 years at recovery levels that exceed the NSPS. In Texas this is because the TACB had already established a high determination of BACT prior to the EPA review which led up to the NSPS. The TACB maintains that those recovery levels still reflect BACT and that it will continue to argue for those sulphur recovery levels. Other states also approved some plants at recovery levels that exceed the NSPS because of case-by-case application of PSD rules. Those states intend to enforce the NSPS but do not intend to use previous PSD determinations of BACT as rigid precedents. In other words, the PSD rules may in some instances require higher sulphur recovery levels than those required by the NSPS, but in the majority of situations the PSD rules will not likely require higher sulphur recovery levels than the NSPS. The two points of view described above are significantly different and we conclude that most of the states we spoke to appear to fall somewhere between these two positions.

- The tiers of rules that apply in most of the states are somewhat difficult to understand and administer. We suspect that industry in the United States would prefer a simpler approach whereby the PSD program would not be necessary and BACT would not need to be defined on a case-by-case basis. We acknowledge that a benefit of this approach is that it facilitates the introduction of new technology.

2.2 Alternative Approaches

One general approach to pollution abatement is to establish a target level of emissions reduction to be achieved over a given period of time. This approach has some appeal where emitters are generally similar in the scale of their operations and few in number where current levels of SO_2 emissions abatement are small to non-existent, and where there is an easily identifiable cause-and-effect relationship between emissions and environmental damage. Alberta's sour gas industry is not easily characterized by any of these factors. The industry is comprised of many plants covering a wide range of production levels; it already recovers a very high proportion of the sulphur; and environmental damage from other sources in other jurisdictions seems to be of a much different order of magnitude than that from Alberta's sour gas industry. As well, because Alberta's industry is relatively mature the ERCB forecasts (Figure 1-3) that sour gas production will begin to decline within 10 years. Thus SO_2 emissions will decline as a natural consequence. In these circumstances an effective target level of emissions would be difficult to establish, and would not alleviate the difficulty of determining which particular plants should be responsible for achieving it.

As well, the above approach is more a means of implementing a policy which has been predetermined; it does not help in determining how far a policy of SO_2 abatement should go.

Another approach could be the development of rules similar to the PSD rules that are administered in the United States. The primary objective of this type of rule is the protection or restoration of ambient air quality and required sulphur recovery levels are set to achieve that goal. While this type of rule appears to be warranted, especially for some pollutants in some areas of the United States because air quality is clearly in jeopardy, the task force concluded that this approach is not necessary in Alberta. Ambient air standards for SO_2 in Alberta are among the most stringent in North America and with the level of industrial development presently in Alberta, ambient SO_2 concentrations are nowhere near approaching the long-term standards.

The task force concluded that the most reasonable approach to evaluate required sulphur recovery levels, with IL 80-24 at one end of the spectrum and BAT at the other end, is to have regard for the costs of requiring additional sulphur recovery as well as possible environmental impact. Within this approach, our views on appropriate levels of recovery were based on our perceptions of the trade-offs between identifiable sulphur recovery costs on one hand, and reasonable assurance of environmental protection on the other hand. In calculating sulphur recovery costs we had regard for the usual types of economic indicators, namely rates of return, project net present values, and marginal costs. The task force evaluated these economic data in light of its perceptions of reasonable environmental protection.

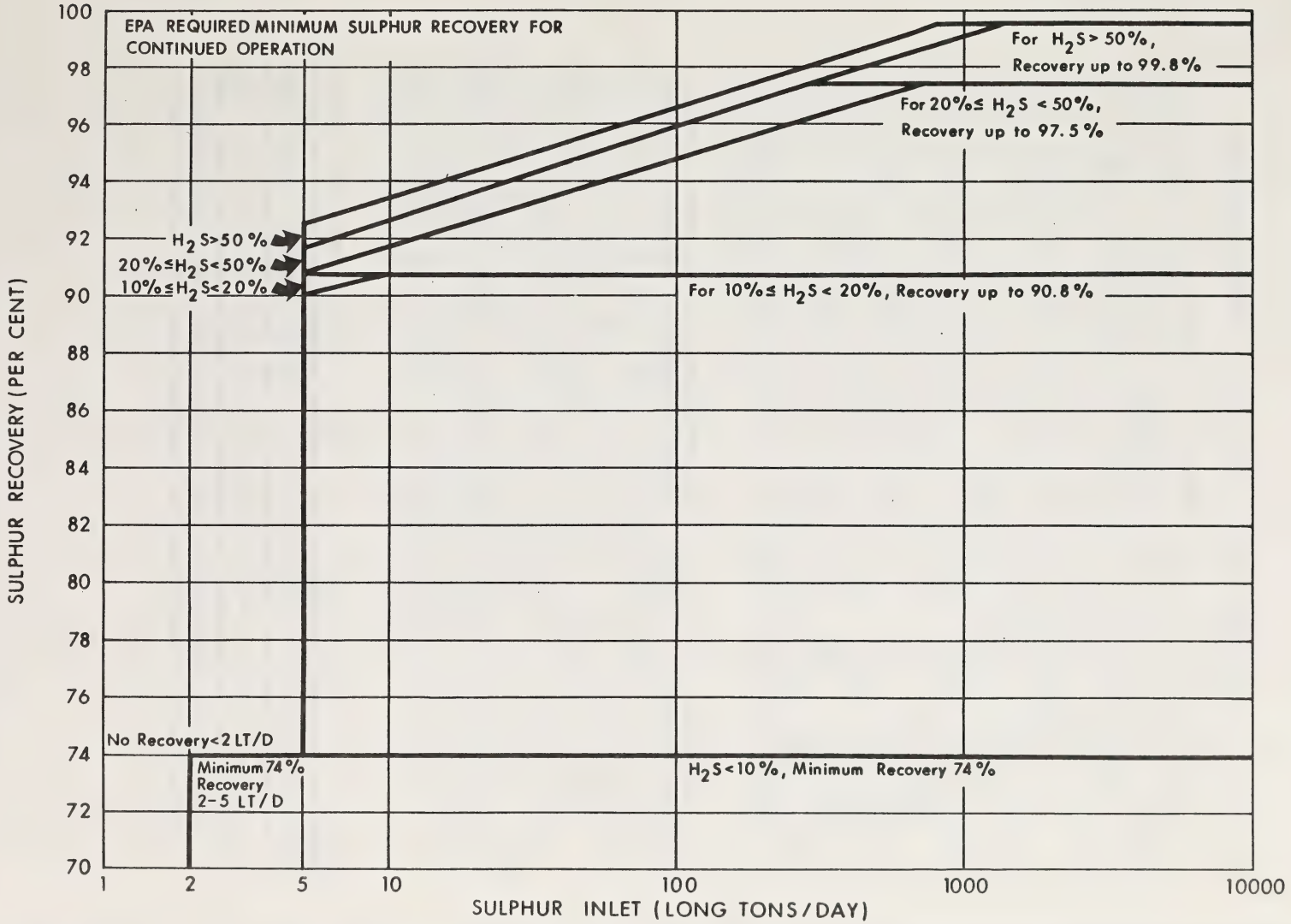

FIGURE 2-1 U.S. EPA NEW SOURCE PERFORMANCE STANDARD FOR ON-SHORE GAS PRODUCTION INDUSTRY

3 SULPHUR RECOVERY AND TAIL GAS CLEAN-UP TECHNOLOGY

Approximately 30 per cent of the natural gas produced in Alberta contains H_2S in concentrations varying from only a trace to more than 50 per cent. In order to produce marketable natural gas from raw sour gas, it must be processed to meet hydrocarbon and water dewpoint specifications and also to remove the H_2S. Very small amounts of H_2S may be removed by non-regenerative types of processes such as Iron Sponge in which the H_2S reacts with an active compound that is consumed in the reaction. These types of processes, however, are not practical for plants which must handle larger amounts of H_2S. These plants typically use some type of regenerative amine system wherein the H_2S (and generally the CO_2 also) is absorbed by the amine in the first step and then stripped in the second step. The gas stripped from the amine is composed essentially of H_2S and CO_2 in varying ratios and is called the acid gas stream. Under the current sulphur recovery requirements in Alberta, if the amount of H_2S in this acid gas stream is less than 10 t/d of equivalent sulphur, it may be burned through a flare stack to convert the H_2S to SO_2 and emitted to the atmosphere. The flare stack must be appropriately designed to ensure compliance with Alberta's ambient air standards respecting ground level concentrations of SO_2.

At plants where the acid gas stream contains more than 10 t/d of sulphur, it must be processed to convert the H_2S to elemental sulphur for recovery. The most commonly used method of sulphur recovery in the sour gas processing industry is the modified-Claus process which reacts H_2S and SO_2 to form elemental sulphur in the vapour phase. Other sulphur recovery processes have been developed more recently which, although not as widely used by industry as the modified-Claus process, have been demonstrated on a commercial scale. These processes include variations of the modified-Claus process wherein the reaction of H_2S and SO_2 is carried out at temperatures below the sulphur dewpoint or where H_2S is oxidized to SO_2 by air prior to the Claus reaction. Processes are also available that oxidize H_2S directly to elemental sulphur in a regenerable, aqueous phase catalyst.

Because the Claus process is unable to convert 100 per cent of the H_2S in the acid gas to elemental sulphur and because of the concerns about emitting SO_2 to the atmosphere, various processes have been developed to treat Claus plant tail gas to remove residual sulphur compounds that would otherwise be emitted. Some of these processes continue the Claus reaction on catalyst beds operated at subdewpoint temperatures to enhance the conversion of H_2S and SO_2 to elemental sulphur. Another group of processes designed to treat Claus tail gas convert

all sulphur compounds present to H_2S by hydrogenation and hydrolysis. The H_2S is then absorbed out of the tail gas and either recycled to the front of the Claus plant or is reacted directly to form elemental sulphur. Still another group of processes oxidizes all sulphur compounds present in the Claus tail gas to SO_2 which is then removed from the tail gas and recycled to the Claus plant or is reacted chemically to form a by-product. It is possible with some of these tail gas clean-up processes to increase the overall sulphur recovery to essentially 100 per cent on a normal operating basis.

We considered the following sulphur recovery processes:

Primary

- Modified-Claus
- COPE
- Linde Oxygen Enrichment
- MCRC
- Selectox/Recycle Selectox
- Stretford Sulphur Removal
- Lo-Cat
- Kellog Oxydesulphurization
- Citrate
- Unisulf
- Sulfint
- Budra One-Step Desulphurization
- Stauffer Sulphur Recovery
- Integrated UCAP

Tail Gas Clean-up

- Sulfreen
- Amoco CBA
- MCRC
- Maxisulf

} Continue Claus reaction at subdewpoint temperatures.

- IFP Clauspol 1500 — Continues Claus reaction in liquid phase.

- SCOT
- BSR/MDEA
- BSR/Stretford
- BSR/Unisulf
- Sulften
- BSR/Selectox
- Oxysulfreen
- ULTRA

} Convert sulphur compounds in Claus tail gas to H_2S for selective absorption and recycle to Claus plant or for direct oxidation to sulphur or for partial oxidation to SO_2 and continuation of Claus reaction.

- UCAP, Wellman-Lord — Convert sulphur compounds in Claus tail gas to SO_2 for selective absorption and recycle to Claus plant.
- Citrate — Converts sulphur compounds in Claus tail gas to SO_2 for Claus reaction with H_2S.
- ATS — Converts sulphur compounds to SO_2 for reaction with ammonia.
- Pritchard CleanAir — Selective absorption of SO_2 and H_2S from Claus tail gas for extension of Claus reaction and liquid phase oxidation of H_2S to sulphur.

Not all of the above processes have been used commercially. As well, some of the above processes are in an advanced stage of development but not yet commercially available.

These processes are described in some detail in Appendix C, along with their design sulphur recovery capabilities and their approximate costs.

Based on our review of sulphur recovery and tail gas clean-up technology, we conclude the following:

1. Demonstrated processes are available that are capable of recovering sulphur to levels above 99.9 per cent on a design basis for all sizes of plants.

2. Direct-oxidation processes are available for plants ranging from very small sulphur inlet rates up to about 15 t/d. These processes are capable of high design sulphur recovery rates (99.9+ per cent) but actual average recovery levels may be less due to operating practice at small plants. Direct-oxidation processes are judged to be the most economical type of process for sulphur recovery at small plants. Sulphur produced by the direct-oxidation processes considered is not saleable without further processing.

3. Selectox and Recycle Selectox processes are variations of the Claus process which are particularly well-suited to processing acid gas streams lean in H_2S that would be difficult to treat with the conventional Claus process. (This poor quality acid gas would most likely occur at plants having sulphur inlet rates ranging from 1 to 50 t/d.) While the economics of using Selectox technology at very small plants are judged by the task force to be less attractive than for the direct-oxidation processes and the sulphur recovery levels achievable are lower (ranging from 70 to 90 per cent depending on number of stages and acid gas), the sulphur recovered is saleable.

4. Extension of the Claus reaction under subdewpoint conditions is well demonstrated technology designed to achieve intermediate recovery levels (97 to 99 per cent) for all sizes of plants down to approximately 10 t/d of inlet sulphur. The subdewpoint processes may be fully integrated with the Claus plant itself resulting in marginal increases in capital and operating costs relative to an equivalent conventional Claus plant. In order to achieve sulphur recovery levels on a continuous basis approaching 99 per cent with a subdewpoint process, the amount of COS and CS_2 in the feed to the subdewpoint reactors must be minimized by treatment in the front end of the plant.

5. Second generation subdewpoint processes have been developed which are capable of enhancing sulphur recovery levels to 99.5 per cent on a design basis by first converting all sulphur species present in the tail gas to H_2S followed by partial oxidation to SO_2 and subdewpoint reactions. This reduces losses due to COS and CS_2 and enables better control of the H_2S/SO_2 ratio entering the subdewpoint reactors.

6. A group of tail gas clean-up processes are available which reduce all sulphur compounds present in Claus plant tail gas to H_2S which then undergoes selective absorption and recycle to the Claus plant or direct oxidation to sulphur. The design capability of these processes range from 99.8 to 99.9 per cent. These processes are applicable for use on plants down to 5 t/d, and have been widely used for treating tail gas from refinery Claus plants. The processes in this group all have net energy requirements, a greater amount for the selective absorption types than the direct oxidation types.

7. A group of tail gas clean-up processes is available that oxidizes all sulphur compounds in the Claus tail gas to SO_2 which is then selectively absorbed. The absorbed SO_2 may then be reacted with H_2S to form sulphur or with other compounds to produce chemical by-products. The design capability of these processes range from 99.8 to 99.9 per cent, but have not been widely applied.

4 ECONOMIC CONSIDERATIONS

4.1 Introduction

During the course of our assessment it became apparent that the type of economic analysis envisioned in the terms of reference would not yield unequivocal solutions to the appropriate level of sulphur recovery.

At its best, economic analysis can offer objective and credible evaluations of alternative investment opportunities. Basically, the stream of costs for a particular undertaking are integrated, in some fashion, with the stream of revenues the project is likely to generate. If the result (usually measured by a rate of return, net present value, discounted benefit-to-cost ratio, and/or years to payout) compares favourably to some benchmark, the project is worthwhile; if it does not, it will not be undertaken.

We find, however, that this methodology is not entirely satisfactory in this analysis. While the incremental costs of additional sulphur recovery can be assessed with some degree of reliability, as has been the object of most of this report, only part of the benefits can be measured with any degree of confidence. The measurable benefits are limited to the value of the additional sulphur recovered and sold.

There is a strongly held view by many people that the market value of the additional sulphur does not fairly represent the total benefits to society from an increase in sulphur recovery. Many believe that, in addition to its commodity value, there would be significant health and environmental-related benefits, and that these should weigh into the benefit/cost analysis. The problem, however, is in assigning a monetary value to these "intangible" benefits. As a result, such an analysis invariably compares tangible capital and operating costs to intangible quality-of-life benefits. Thus, without having a clear idea of the total social benefits of reduced sulphur emissions, we cannot claim that more restrictive guidelines, with accompanying financial costs, would be justified. By the same token we cannot say that such investment would not be worthwhile from society's point of view.

With these comments we do not mean to convey the idea that the terms of reference were onerous, nor that we were prevented from coming to meaningful conclusions. What we would like to make clear at this point is the distinction between the objective and subjective aspects of a review of sulphur recovery guidelines.

All of the economic parameters discussed in this report refer only to the measurable costs of reducing sulphur emissions from levels that are permitted by the current guidelines. For example, we calculated the potential effects on project rates of return from requiring more sulphur recovery. As well, we calculated the total additional capital and operating costs for a given type of facility, and the marginal costs per tonne of additional sulphur recovered. We consider these elements to form the objective part of the analysis.

The subjective element comes in when one attempts to compare the calculated costs of abatement to the benefits of reduced sulphur emissions. For example, if one is of the view that sulphur emissions are always and everywhere a hazard to be avoided at any cost, it is axiomatic that the deemed benefits to society from reducing sulphur emissions are always worth whatever it costs to avoid them (even if that implies leaving the sour gas in the reservoir). At the other end of the spectrum, one could be of the view that environmental and social costs of sulphur emissions are negligible and, therefore, sulphur should be recovered only to the point where it is no longer profitable to recover more. (In this case, "guidelines" would be redundant since the industry would recover the appropriate amount of sulphur on its own accord.)

It was not within our terms of reference to attempt an assessment of environmental damage from sulphur emissions. However, having assessed the costs of sulphur abatement, any recommendation as to the disposition of guidelines has to be based on some notion of the likely benefits to society from reducing sulphur emissions, no matter how subjective the judgement may be.

4.2 General Approach

We used three kinds of economic indicators in our analysis. First is the potential change in the after-tax rate of return to sour gas developments, that could result from the imposition of stricter sulphur recovery guidelines. The change in rate of return can be used to speculate on the possible impacts of stricter guidelines on future sour gas activity in Alberta. This would constitute an "affordability assessment".

Second, we determined the change in the net present values of projects under alternative recovery levels. A baseline net present value was calculated as discounted revenues (from sales gas, condensate, and sulphur) less discounted costs (capital and operating). This value reflects the pre-tax profits to be divided amongst the federal and provincial governments, and the plant owners. Net present values were

then calculated under alternative sulphur recovery requirements, and the difference reflects the additional costs to society of recovering additional sulphur.

An alternative we rejected for our rate of return and net present value calculations we rejected the methodology which involves a profitability assessment of sulphur plants as discrete projects. In such an approach one would ignore the revenues and costs associated with development, gathering and sweetening, and base the economic analysis on the sulphur plant alone. The difference in net present value or rate of return between two different sulphur recovery levels would be calculated, and if there was not an extraordinarily large drop in either indicator, it could be suggested that the effects of stricter guidelines would have a negligible effect on industrial development.

In our view this is somewhat of a piecemeal approach and is likely to be misleading. It appears to us that sulphur recovery is only one part of a large investment with other associated cost and revenue streams. To isolate the sulphur recovery process and assess its profitability would not give a true picture of the economics of sour gas developments.

By way of analogy, years ago when natural gas liquids prices were relatively low and would not usually justify installation of liquids recovery facilities in the field, pipeline specifications nevertheless required extraction to some extent. Even though liquids extraction would not usually have been profitable on its own merits, it was sometimes one of the costs of recovering gas reserves. Thus, it was the economics of the overall project that determined whether or not development would occur, not the merits of the individual components considered in isolation.

Following from this, we are more interested in putting sulphur economics in the context of an overall development, superimposing different sulphur recovery guidelines on various base-cases, and assessing whether or not alternative guidelines would materially affect future similar developments. We wish to stress that the projects profiled in this report assume that the reservoir has already been discovered and to some extent delineated. Thus, the task force ignored exploration costs and exploration drilling success rates. As a result the rates of return that we calculated are exaggerated. If people were to believe that it is legitimate to compare these apparent rates of return to, say, the interest rate one receives on a savings account, nobody would have savings accounts. On the other hand, we believe the calculated changes in the rates of return fairly reflect a realistic result of alternative guidelines. In other words the task force paid more attention to the changes in rates of return than to their apparent levels.

A disadvantage of this method is that similar sized plants, from a sulphur inlet viewpoint, may have vastly different throughputs of gas and natural gas liquids, thus making profitability extremely variable and of varying sensitivity to incremental sulphur recovery costs. Section 4.3 describes the task force's specific assumptions regarding this and other economic parameters.

Our third economic indicator was the net marginal cost per tonne of additional sulphur beyond what is currently recovered. This last value has been variously referred to by others as "incremental levelized cost", "unit annualized capital and operating cost", and "long-run marginal cost" among, perhaps, other similar types of names. We refer to it as the marginal costs per tonne of additional sulphur recovered.

We reviewed the incremental cost calculations with two purposes in mind. The first was to determine the value of additional capital, labour, and other resources that would be required to reduce sulphur emissions beyond the current guidelines, net of the commodity value of the additional sulphur recovered. This would represent the net costs to society of requiring higher levels of sulphur recovery in terms of the effects on corporate revenues, provincial royalties and taxes, and federal taxes.

The second purpose was to determine, as a result of the above calculation, the implicit value that society would be assigning to environmental damage from sulphur emissions if society were to require stricter guidelines. In other words let us say the labour, capital and other costs of recovering one extra tonne of sulphur were $535 and a tonne of sulphur sells for $135. The difference, $400, is the net cost to society of recovering that extra tonne of sulphur. If guidelines are imposed that require this to be done, society would implicitly be saying that if the sulphur was otherwise emitted to the atmosphere, it would cause at least $400 of environmental damage. This $400, then, would represent the implicit cost of environmental damage from sulphur emissions. The implicit costs are provided as an indication of what society would have to believe to be likely if society is to justify stricter guidelines.

4.3 General Economic Parameters

We analysed all of the sour gas processing schemes with a publicly available computer model[1]. We believe that the use of a model that has been widely used by the industry was preferable to building

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1 Profitability of Oil and Gas Opportunities (POGO) model which is owned by PSI Limited.

our own "black box" which would not likely yield more credible results. The model gives its users the flexibility to incorporate a wide array of economic parameters depending on the particular circumstances. For our study the following general assumptions were made:

1. A construction period of 1 year was assumed for all facilities associated with projects in the 1 to 50 t/d range, and 2 years for projects greater than 50 t/d.

2. The project's taxes were calculated on a "stand-alone" basis at prevailing marginal tax rates.

3. The Alberta Royalty Tax Credit was not applied in any of the analyses under the assumption that the maximum credit of $3 million would have been reached by most producers already.

4. The initial year's production was held constant for 5 years, reduced by 5 per cent in the 6th year, and by 10 per cent of a declining balance thereafter.

5. Product prices at the plant gate in 1987 were assumed to be $\$60/10^3$ m^3 for gas (about \$1.60/GJ), $\$185/m^3$ for condensate, and \$135/t for sulphur.

6. Product prices were assumed to increase at a nominal rate of 5 per cent per year.

7. Both fixed and variable operating costs were assumed to increase at the rate of 5 per cent per year.

8. All revenues and costs were discounted at the nominal rate of 15 per cent to mid-year values. The reference year is 1987.

4.3 Engineering Parameters

Sulphur Plants

Capital and operating costs were estimated for sour gas processing schemes having sulphur inlet rates of 1 t/d, 2 t/d, 5 t/d, 10 t/d, 50 t/d, 350 t/d, 1000 t/d, and 2500 t/d. For the cases studied up to 10 t/d, direct oxidation type processes were considered to be the least costly to apply and at the same time were capable of achieving the highest sulphur recovery levels. For the 50, 350, and 1000 t/d cases, depending on the type of technology required under the current guideline, the effort of installing some technology to achieve an intermediate or best possible recovery level was examined. For the

2500 t/d case, we considered the use of BAT as already being necessary to achieve the recovery levels required under the current guideline. The type of processes proposed as necessary to meet IL 80-24, an intermediate level, and the highest possible recovery level are shown in Table 4-1. The reader should note that the technology selected as being necessary to meet the current guideline is capable of achieving recovery levels exceeding the minimum required. The acid gas qualities which were used in estimating the sulphur plant costs, 15 per cent H_2S and 85 per cent CO_2 (15/85) for the 1, 2, 5, and 10 t/d sizes, 50/50 for the 50 t/d size, and 80/20 for the 350, 1000, and 2500 t/d sizes were selected as being representative of a typical situation. Capital and operating costs for sulphur recovery and tail gas clean-up processes capable of achieving the base, intermediate, and high levels of sulphur recovery are shown in Table 4-2.

Capital and operating costs for the sulphur plant cases have been derived largely from a study of the subject undertaken in 1982 and 1983 by MHG International Ltd. for Environment Canada[2]. Where we have considered processes which were not included in the MHG study, absolute and relative cost information was derived from various published sources. Because of the downturn in oil and gas activity in Alberta in recent years and the current prevailing economic climate, we believe that the 1982 cost information contained in the MHG report reasonably reflects current capital and operating costs.

The capital costs in Table 4-2 account for the sulphur plant, a tail gas clean-up unit where applicable, an incinerator with a 76 metre stack (for all cases except where the use of BAT would necessitate standby equipment only), and for sulphur forming and handling facilities for all cases greater than 50 t/d.

Direct operating costs were calculated by adjusting the MHG data to appropriate sulphur inlet rates and acid gas quality for the cases considered in this review. Assumptions used for both variable and fixed operating costs are essentially the same as contained in the MHG report with the exception of the credit given for sulphur plant steam production. In this analysis, the value assigned to sulphur plant steam was based on its heating energy and on an assumed 75 per cent efficiency factor of producing that energy from fuel gas. All of the high-pressure steam and half of the medium-pressure steam was assumed to be directly usable within the gas plant, hence, a fuel gas saving. Low-pressure steam produced in the sulphur plant was assumed to be

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2 Investment and Operating Cost Study, Sulphur Recovery Facilities, Natural Gas Processing Industry, Environment Canada, FED-0254, by MHG International Ltd., March 1983.

unusable and, therefore, was not given a value. In this way, the credit for that part of the produced steam which is assumed to be used in the gas plant can be equated to a volume of gas which would have been used as fuel in the plant but, instead, can be sold.

Fixed and variable operating costs for each case are shown in Table 4-2. Information regarding sulphur plant utilities is shown in Table 4-3 in support of the variable operating cost figures.

Total Gas Processing Scheme

For the economic analyses, several of the sulphur plant cases were added to various sizes of gas plants. Gas plant sizes were selected to represent the low end of the scale in terms of volume of raw gas corresponding to a given sulphur inlet rate, based on actual Alberta plants. The gas was assumed to not contain propane or butane in recoverable quantities, however, it was assumed to contain the provincial average amount of pentanes plus. Gathering systems and gas plants were assumed to operate at 85 per cent of capacity over 350 operating days per year, considering seasonal variations in demand for gas and annual plant turnaround. The throughput and economic parameters assumed for the plants are shown in Table 4-4.

Gas plant capital costs were estimated after reviewing cost data for existing plants in Alberta of similar sizes and processes. Capital costs for field development include the cost of drilling development wells (an increasing number of wells with increasing plant size) and the cost of a gathering system to connect the wells to the plant. As stated earlier, exploration drilling with associated risk factors was not considered. Operating costs for the field (wells and gathering system) and for the plant were assumed to be 10 per cent of the capital costs for both. These costs were split on a 50/50 basis between fixed and variable operating costs.

We appreciate that capital costs for wells, pipelines, and plants are subject to very significant variation from one scheme to another, as would be the overall profitability. The absolute value of the assumed costs, however, becomes less important when used in a relative sense to compare the effects of the increased sulphur recovery levels on profitability.

SKM Consulting Ltd. was commissioned to review sections 3 and 4.3 of the report, and they were in general agreement with our process assessments and engineering parameters.

4.4 Results

The results of the case-by-case analyses are presented in Tables 4-5, 4-6, and 4-7. Following are descriptions of the construction of the numbers in the tables and our interpretation of their meaning.

Table 4-5 shows the calculated after-tax rates of return under alternative recovery levels. Consistent with the assumptions and methodology discussed in Sections 4.1 to 4.3, a project rate of return was calculated for a sour gas development which was assumed to proceed under IL 80-24. A new rate of return was calculated when stricter guidelines were superimposed on the project.

As discussed in Section 4.2, we do not attach a lot of significance to the numbers as they stand in Table 4-5. Exploration costs and risk factors would reduce these apparent rates of return considerably.

What we believe to be of some significance, though, are the changes in the apparent rates of return. In some cases (going from IL 80-24 to intermediate technology where it is available) these changes seem rather trivial, and easily affordable. In other cases (going from IL 80-24 to BAT) the changes are rather more significant and could, in our opinion, have a measurable effect on sour gas development in Alberta.

Table 4-6 describes the task force's estimates of pre-tax revenues and production costs under the various cases studied. In the 1 and 2 t/d cases, the revenues without and with new guidelines are identical because the sulphur production under BAT is not a marketable product. In the 5 and 10 t/d cases, the increased revenue is due entirely to sulphur production assumed to be marketable. In the remaining cases increased sulphur revenues were offset, to a large extent, by the reduction in steam that otherwise could have displaced fuel gas in the sweetening plant. This substitution reduces available marketable gas and, hence, revenues from gas sales.

The differences in production costs between columns 2, 3, and 5 are solely attributable to the increased capital and operating costs of enhanced sulphur recovery.

The difference between revenues and costs (pre-tax net revenues) is the net income that would be divided amongst the plant owners, provincial government, and federal government. For example, under each level of technology the disposition of net revenue accruing in the 350 t/d case would be as follows:

	IL 80-24 ($\times 10^3$)	Int. Tech. ($\times 10^3$)	BAT ($\times 10^3$)
Corporate after-tax income	$33 288	$32 190	$28 240
Provincial royalties and taxes	28 461	27 829	25 489
Federal taxes	24 002	23 643	22 283
	$85 750	$83 663	$76 011

The above disposition of net revenue indicates that going from IL 80-24 to, for example, BAT, would reduce shareholder income by some $5 million, would reduce provincial royalties and taxes by some $3 million, and federal taxes by about $1.8 million, for a total cost to society of about $10 million. (Under the 350 t/d case, this equals the sum of columns 4 and 6 in Table 4-6.)

One could be of the view that, given the magnitude of the numbers involved, a reduction of corporate income of $5 million (in the 350 t/d case) would not be greatly missed and would not, therefore, affect industry activity. As well, one could postulate that a decline in provincial and federal government revenues of $3 million and $2 million respectively does not really amount to much in the whole scheme of things, considering that these changes would occur over 21 years. Indeed, as will be seen in Section 5, some task force members adopted this type of "affordability test" as the primary decision making criterion. Other members took the view, however, that because an individual, a corporation, or society may be able to afford any given undertaking, that does not provide compelling or sufficient grounds to undertake it.

Table 4-7 identifies the marginal costs per tonne of sulphur that would be recovered under guidelines stricter than IL 80-24. These costs represent the capitalized value of changes in capital and operating costs, steam credits, and sulphur revenues that would be imposed by higher recovery levels. For example, for a 5 t/d plant to recover all of its sulphur inlet, Table 4-6 identified that such recovery would come at a net discounted cost to society of about $2.2 million (in terms of foregone taxes, royalties, and corporate profits). That is, some $2.2 million worth of capital and operating costs would be spent over and above the market value of sulphur recovered during the 20-year life of the project. From Table 4-7 it is seen that $2.2 million translates into about $220/t, which is the price over and above the commodity value of $135/t that would have to be received from each tonne of sulphur recovered over 20 years to equate to a present discounted value of $2.2 million. (This price must inflate along with other prices and costs at the rate of 5 per cent per year beginning in 1988, such that by 1997 it stands at about $360/t.)

The $220/t figure noted above may also be interpreted as the real value of environmental damage, as of 1987, that would justify recovering the sulphur.

The general formula used in this analysis for calculating the net marginal costs as presented in Table 4-7 is,

$$\text{Net Marginal Cost} = \frac{\sum_{t=o}^{T} \frac{Kt + OCt - SCt - SRt}{(1+n)t}}{\sum_{t=o}^{T} \frac{Qt}{(1+r)t}}$$

where: Kt = change in capital costs in year "t"

OCt = change in operating costs in year "t"

SCt = change in value of steam credit in year "t"

SRt = change in sulphur revenue in year "t"

Qt = change in sulphur production in year "t"

T = project life in years

n = nominal discount rate = 0.15 (15%)

r = real discount rate = 0.0952381 (9.5%)

and (1+n) = (1+r)(1+f)

f = rate of inflation = 0.05 (5%)

We appreciate that alternative assumptions can be made regarding the choice of sulphur prices, discount and inflation rates, and the like. We believe, however, that the assumptions used in this analysis are reasonable and fairly reflect appropriate considerations.

TABLE 4-1 SELECTED PLANT SIZES, PROCESSES, AND RECOVERY LEVELS

Sulphur Inlet (t/d)	Acid Gas Quality (H_2S/CO_2)	Process and Recovery Efficiency[a]		
		Base (IL 80-24)	Intermediate	BAT
1	15/85	-	-	Direct Oxidation (96.0)[b]
2	15/85	-	-	Direct Oxidation (96.0)[b]
5	15/85	-	-	Direct Oxidation (96.0)[b]
10	15/85	-	-	Direct Oxidation (96.0)[b]
50	50/50	Claus (96.2)	Claus/Subdewpoint (98.5)	Claus/Selective Absorption (99.8)
350	80/20	Claus/Subdewpoint (98.7)	Claus/Subdewpoint (98.8)	Claus/Selective Absorption (99.8)
1000	80/20	Claus/Subdewpoint (98.8)	Claus/Subdewpoint w/Intermediate Hydrogenation (99.5)	Claus/Selective Absorption (99.8)
2500	80/20	Claus/Selective Absorption (99.8)	N/A	N/A

a Sulphur recovery levels achievable across the sulphur plant averaged over long-term, continuous operation. The values shown are less than design rates achievable under performance test conditions to account for operational variations experienced over a long term. The values shown are efficiencies for the sulphur plant and tail gas clean-up unit only and do not include an allowance for flaring of acid gas or raw gas.

b Sulphur recovery unit downtime of approximately 4 per cent would result in average sulphur recovery efficiency of 96 per cent where design rate would have been in the order of 99.95 per cent. The occurrence of this amount of downtime would be reasonable to expect at small plants operating partially unattended.

TABLE 4-2 SULPHUR PLANT CAPITAL AND OPERATING COSTS

Sulphur Inlet (t/d)	Acid Gas (H_2S/CO_2)	Process	Capital Cost (10^6 $)	Variable Operating Cost (10^3 $/year) @ Design Rate	Fixed Operating Cost (10^3 $/year)	Fuel Gas Credit (10^6 m^3/year)
1	15/85	Direct Oxidation	0.47	105	54	-
2	15/85	Direct Oxidation	0.83	160	65	-
5	15/85	Direct Oxidation	1.6	230	88	-
10	15/85	Direct Oxidation	2.5	335	120	-
50	50/50	Claus	4.6	237	264	2.7
50	50/50	Subdewpoint	4.9	239	273	2.7
50	50/50	Claus/Selective Absorption	8.0	227	408	2.0
350	80/20	Subdewpoint	18.4	1 760	720	29.8
350	80/20	Subdewpoint (additional converter)	20.4	1 780	780	29.8
350	80/20	Claus/Selective Absorption	27.0	1 820	1 020	22.5
1000	80/20	Subdewpoint	43.8	5 800	1 470	75.3
1000	80/20	Claus/Subdewpoint w/Intermediate Hydrogenation	61.6	6 700	2 100	73.8
1000	80/20	Claus/Selective Absorption	55.4	5 900	1 950	70.7
2500	80/20	Claus/Selective Absorption	144.0	13 000	4 740	161.0

TABLE 4-3 SULPHUR PLANT UTILITY RATES

Sulphur Inlet (t/d)	50	50	50
Acid Gas Quality (H_2S/CO_2)	50/50	50/50	50/50
Process	Claus	Subdewpoint	Claus/ Selective Absorption
Utilities Required			
Boiler feedwater, kg/hr	5831	5831	6164
Electricity, kW	148	148	139
Fuel gas, m^3/hr	149	149	105
345 kPa steam, kg/hr	-	-	-
Cooling water, m^3/hr	-	-	144
Utilities Produced			
4140 kPa steam, kg/hr	3586	3586	3586
345 kPa steam, kg/hr	1749	1749	586
105 kPa steam, kg/hr	330	330	-
Steam condensate, kg/hr	167	167	1993
Catalyst and Chemicals $/day	22	26	54

TABLE 4-3 continued

Sulphur Inlet (t/d)	350	350	350
Acid Gas Quality (H_2S/CO_2)	80/20	80/20	80/20
Process	Subdewpoint	Subdewpoint (additional converter)	Claus/ Selective Absorption
Utilities Required			
Boiler feedwater, kg/hr	49 630	49 630	53 704
Electricity, kW	791	800	900
Fuel gas, m^3/hr	360	360	390
345 kPa steam, kg/hr	-	-	3 378
Cooling water, m^3/hr	-	-	1 181
Utilities Produced			
4140 kPa steam, kg/hr	36 785	36 785	39 970
345 kPa steam, kg/hr	10 115	10 115	-
105 kPa steam, kg/hr	-	-	-
Steam condensate, kg/hr	2 730	2 730	17 112
Catalyst and Chemicals $/day	127	162	402

TABLE 4-3 continued

Sulphur Inlet (t/d)	1000	1000	1000
Acid Gas Quality (H_2S/CO_2)	80/20	80/20	80/20
Process	Subdewpoint	Claus/ Subdewpoint w/Intermediate Hydrogenation	Claus/ Selective Absorption
Utilities Required			
Boiler feedwater, kg/hr	141 800	157 000	153 500
Electricity, kW	2 286	2 860	2 540
Fuel gas, m^3/hr	1 029	2 230	1 118
345 kPa steam, kg/hr	-	-	9 650
Cooling water, m^3/hr	-	362	3 370
Utilities Produced			
4140 kPa steam, kg/hr	105 100	114 200	114 200
345 kPa steam, kg/hr	28 900	35 400	-
105 kPa steam, kg/hr	-	2 190	-
Steam condensate, kg/hr	7 800	5 210	48 950
Catalyst and Chemicals $/day	463	800	1 234

TABLE 4-3 continued

Sulphur Inlet (t/d)	2500
Acid Gas Quality (H_2S/CO_2)	80/20
Process	Claus/ Selective Absorption
Utilities Required	
Boiler feedwater, kg/hr	383 750
Electricity, kW	6 350
Fuel gas, m^3/hr	2 795
345 kPa steam, kg/hr	24 125
Cooling water, m^3/hr	8 425
Utilities Produced	
4140 kPa steam, kg/hr	285 500
345 kPa steam, kg/hr	-
105 kPa steam, kg/hr	-
Steam condensate, kg/hr	122 375
Catalyst and Chemicals $/day	3 085

TABLE 4-4 ECONOMIC PARAMETERS FOR SELECTED SOUR GAS PROJECTS

Sulphur Inlet (t/d)	1	2	5	10	50	350	1000	2500
Raw Gas Inlet (10^3 m^3/d)	85	120	185	270	400	1000	2000	5000
H_2S in Raw Gas (%)	0.9	1.2	2.0	3.0	10	25	35	35
C_5+ Product (m^3/d)	6	8	12	13	25	60	120	300
Capital Cost (10^6 $)								
Field Development								
- Wells	2	2.5	3	3.5	8	15	20	40
- Pipelines	0.75	1.0	1.25	1.5	2.5	3	6	12
Gas Plant								
- Gas Conditioning	1.5	2.0	3	5	10	20	40	100
- Sulphur Plant	*	*	*	*	*	*	*	*

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* Sulphur plant capital investment shown in Table 4-2.

TABLE 4-5 CALCULATED AFTER-TAX RATES OF RETURN UNDER ALTERNATIVE RECOVERY LEVELS[a]

Sulphur Inlet (t/d)	IL 80-24 (%)	Intermediate Technology (%)	Best Available Technology (%)
1	22.1	N/A[b]	16.5
2	22.8	N/A[b]	17.8
5	24.9	N/A[b]	19.1
10	24.1	N/A[b]	18.1
50	17.5	17.4	14.5
350	29.1	28.3	25.8
1000	35.3	N/A[b]	32.6
2500	33.7	N/A[c]	N/A[c]

a These are after-tax rates of return consistent with the assumptions described in Sections 4.1, 4.2, and 4.3.

b In these cases, the intermediate technology was more costly than BAT and was, therefore, ignored.

c For the 2500 t/d case IL 80-24 is equivalent to BAT.

TABLE 4-6 DISCOUNTED REVENUES AND COSTS UNDER ALTERNATIVE RECOVERY LEVELS

1 Sulphur Inlet Rate t/d		2 IL 80-24 10^3 $	3 Intermediate Technology 10^3 $	4 Change (3-2) 10^3 $	5 BAT 10^3 $	6 Change (5-3) 10^3 $
	Pre-tax revenue	10 521			10 521	
1	Production costs	6 845	N/A		8 294	
	Pre-tax net revenue	3 676			2 227	- 1 449
	Pre-tax revenue	14 588			14 588	
2	Production costs	8 858	N/A		11 023	
	Pre-tax net revenue	5 730			3 565	- 2 165
	Pre-tax revenue	21 041			22 307	
5	Production costs	11 677	N/A		15 123	
	Pre-tax net revenue	9 364			7 184	- 2 180
	Pre-tax revenue	28 055			30 586	
10	Production costs	16 099	N/A		21 216	
	Pre-tax net revenue	11 956			9 370	- 2 586
	Pre-tax revenue	54 624	54 941		55 095	
50	Production costs	40 744	41 106		45 039	
	Pre-tax net revenue	13 880	13 835	- 45	10 056	- 3 779
	Pre-tax revenue	170 838	170 910		170 613	
350	Production costs	85 088	87 257		94 602	
	Pre-tax net revenue	85 750	83 663	-2 087	76 011	- 7 652
	Pre-tax revenue	391 317			392 280	
1000	Production costs	168 291	N/A		181 780	
	Pre-tax net revenue	223 026			210 500	-12 526
	Pre-tax revenue	976 076				
2500	Production costs	438 094	N/A		N/A	N/A
	Pre-tax net revenue	537 982				

TABLE 4-7 MARGINAL COSTS PER TONNE OF SULPHUR EMISSIONS ABATEMENT[a]

Sulphur Inlet (t/d)	IL 80-24 to Int ($/t)	Int to BAT ($/t)	IL 80-24 to BAT ($/t)
1	N/A	N/A	720
2	N/A	N/A	540
5	N/A	N/A	220
10	N/A	N/A	130
50	20	2 900	2 920
350	3 250	1 190	4 440
1 000	N/A	N/A	680
2 500[b]	N/A	N/A	N/A

a These calculations represent the constant dollar value (as of 1987) of the net costs of additional sulphur recovery over and above commodity value of sulphur ($135/t).

b Since IL 80-24 already requires BAT, there are no additional marginal costs to consider. The task force notes, however, that the marginal cost in going from subdewpoint (98.8%) technology to BAT (99.8%) is about the same as in the 1000 t/d case.

5 RECOMMENDATIONS FOR NEW SULPHUR RECOVERY GUIDELINES

5.1 Summary

The task force was divided as to how the economic analyses should be interpreted. Consequently, we did not reach a unanimous conclusion for proposing a new guideline. Alternative proposals are illustrated in Figure 5-1, both unanimous and otherwise. The major conclusions are summarized as follows:

- the solid line on Figure 5-1 represents the recovery levels that industry would achieve if the current guideline remains unchanged,
- a sulphur recovery level of 90 per cent would be a reasonable requirement for plants between 5 and 10 t/d, as illustrated on Figure 5-1,
- sulphur recovery levels shown as the solid and dashed lines on Figure 5-1 should be set as minimum required levels,
- some members of the task force believe that the above adjustment IL 80-24 is the only amendment that is reasonably justifiable and would not propose further adjustment (this constitutes Proposed Alternative 1),
- other task force members believe that the recovery levels as illustrated by the dotted lines on Figure 5-1 are reasonably justifiable (this constitutes Proposed Alternative 2), and
- BAT is capable of achieving essentially 100 per cent recovery at all plant sizes but the task force does not propose BAT as a general guideline.

5.2 Discussion

The task force is of the view that while certain types of technology are necessary to meet the minimum requirements of the current guideline for any plant larger than 10 t/d, the recovery levels achievable with that technology exceed the requirements in most cases. On Figure 5-1, the task force has illustrated its interpretation of the de facto recovery levels required by the current guideline. Tail gas clean-up of the selective absorption type or equivalent is required for plants larger than 2000 t/d. This technology is capable of achieving 99.8 per cent recovery on a continuous basis and represents BAT. Subdewpoint technology is adequate to meet the current requirements for plants between 50 and 2000 t/d. This technology is capable of achieving between 98.5 and 98.8 per cent

recovery on a continous basis, depending on acid gas quality. For plants between 10 and 50 t/d, conventional Claus technology is adequate to meet the current requirements. The 3-stage Claus process is capable of achieving approximately 96 per cent, assuming reasonable quality acid gas feed.

The task force concluded that the current minimum requirements could be adjusted upwards to the levels depicted by the solid line on Figure 5-1 without requiring the use of different technology than would otherwise have been used. Such an adjustment would more closely reflect the recovery levels that would be achieved by industry in meeting the current minimum requirements.

The results of the economic analyses led all task force members to conclude that for plants between 5 and 10 t/d, sulphur recovery could reasonably be required without causing severe impacts on the industry. This judgement is based on the relatively small marginal costs and minimal changes to project profitability. While the economic analyses assumed the use of a direct oxidation type of process because it appeared to be the least costly, the task force did not see a need to propose a recovery level that would preclude the use of other processes that could be developed for use in this size range. For this reason, a minimum recovery level of 90 per cent for plants between 5 and 10 t/d is proposed by the task force, as shown by the dashed line on Figure 5-1. The combination of the solid and dashed lines on Figure 5-1 constitute Proposed Alternative 1.

For the remaining plant sizes, the task force was not unanimous on its views of requiring the next level of recovery. For two of the members IL 80-24, with an extension to plants between 5 to 10 t/d, would be an appropriate guideline. These members believe that, by and large, such a guideline provides adequate assurance of environmental protection and that additional changes are not warranted. They feel that affordability should not be an important criterion in determining appropriate levels of sulphur recovery and that any financial cost incurred by society to recover more sulphur should be at least notionally offset by perceived environmental benefits. Since applied economics leaves a lot to be desired in ascribing monetary values to environmental factors, any value that is deemed is likely to be arbitrary. Despite the subjective nature of such a deemed value, some members believe that sulphur recovery should not be required when the marginal costs would exceed the commodity's value by more than $200/t. (This value is intended to reflect the views of these members with respect to this particular industry in Alberta and is not to be interpreted to apply to all industries in all regions.) In the opinion of these members, advocating sulphur recovery beyond the levels already in effect in Alberta and beyond the point where net marginal costs exceed $200/t borders on advocating a pound of prevention for an ounce of cure.

The other two task force members are of the view that while marginal costs are a valid indicator of sulphur production costs and could be used to determine the degree of recovery that would maximize sulphur revenues, they are of limited use for comparing with unquantified, possible environmental costs. Within this view, more weight is placed on changes in project profitability resulting from increased recovery. As a second proposed alternative, these task force members recommend further changes, as shown by the dotted line on Figure 5-1.

This alternative reflects the view by some members that recovery levels could reasonably be increased beyond the recommended minimum, without significant impact on project economics. As can be seen from the figure, for plants in the 1000 to 2000 t/d range the proposal would result in the use of selective amine absorption or equivalent type of tail gas clean-up unit being required where previously, subdewpoint technology would have been acceptable. Similarly, plants in the 20 to 50 t/d range would be required, under this proposal, to install subdewpoint technology where previously conventional 3-stage Claus technology would have been accepted. For plants in the 1 to 5 t/d range, this proposal would require a minimum of one stage of Claus (or another process capable of achieving at least 70 per cent) sulphur recovery to be installed where previously, flaring of the acid gas would have been acceptable.

The task force members proposing this alternative suggest that the marginal costs and other financial impacts associated with this alternative would not represent a significant burden on the industry (in fact only affecting certain size projects) and would not curtail the development of Alberta's sour gas resources. At the same time, the proposal would result in some reduction in future emissions. A potential benefit of the proposed recovery levels at the small plants, 1 to 5 t/d, would be a possible reduction in local opposition with associated costs of project delays and regulatory requirements.

The task force was unanimous in the view that BAT is capable of recovering essentially 100 per cent of the sulphur inlet for all sizes of sour gas plants. The results of the economic analysis show, however, that with the exception of the very large plants, where the current recovery levels already require the use of BAT, the cost of increasing recovery levels to BAT for all other plants would be excessive and could have a significant impact on the industry. The marginal costs of installing BAT for some plant sizes are as high as $3000/t of additional sulphur recovered. As well, changes in project rates of return are in the order of 5 percentage points, which we believe is significant. For these reasons the task force concluded that it would be unreasonable to propose BAT for all plants.

5.3 Other Conclusions and Recommendations

The sulphur recovery levels indicated on Figure 5-1 are to be viewed in the same general manner as the figure that was attached to IL 80-24. That is, Figure 5-1 depicts anticipated long-term average levels of sulphur recovery. We recommend deducting 0.3 per cent (as has been done since 1980) when determining the minimum quarterly average requirement that would be stated in the ERCB approval, and that this be used as the surveillance level. ERCB records show that 0.3 per cent is the typical difference between minimum quarterly requirements and long term average levels achieved. We recommend that in future, ERCB approvals state both the minimum quarterly requirement (for surveillance purposes) and the anticipated long-term average recovery level (for information purposes).

For plants larger than 10 t/d, the lines on Figure 5-1 are intended to represent long-term average recovery levels expected for average and high quality acid gas; those with ratios of H_2S/CO_2 exceeding 40/60. For plants smaller than 10 t/d, it is more likely that the H_2S/CO_2 ratio will be lower than 40/60. (However, technology recently developed for handling small amounts of sulphur is also directly aimed at low ratios of H_2S/CO_2). The task force believes that under any guideline instances may arise when factors, such as exceptionally poor acid gas quality, could deter development. We recommend that any such cases be considered on an individual basis to determine whether or not strict adherence to the guideline is advisable.

We believe that promising but unproven technology should be encouraged in Alberta. Having regard for the uncertainty of the sulphur recovery capability any new technology, we believe that some leniency may be appropriate if the new technology does not meet expectations. Such plants should be reviewed, say 5 to 10 years after start-up to determine appropriate remedial action.

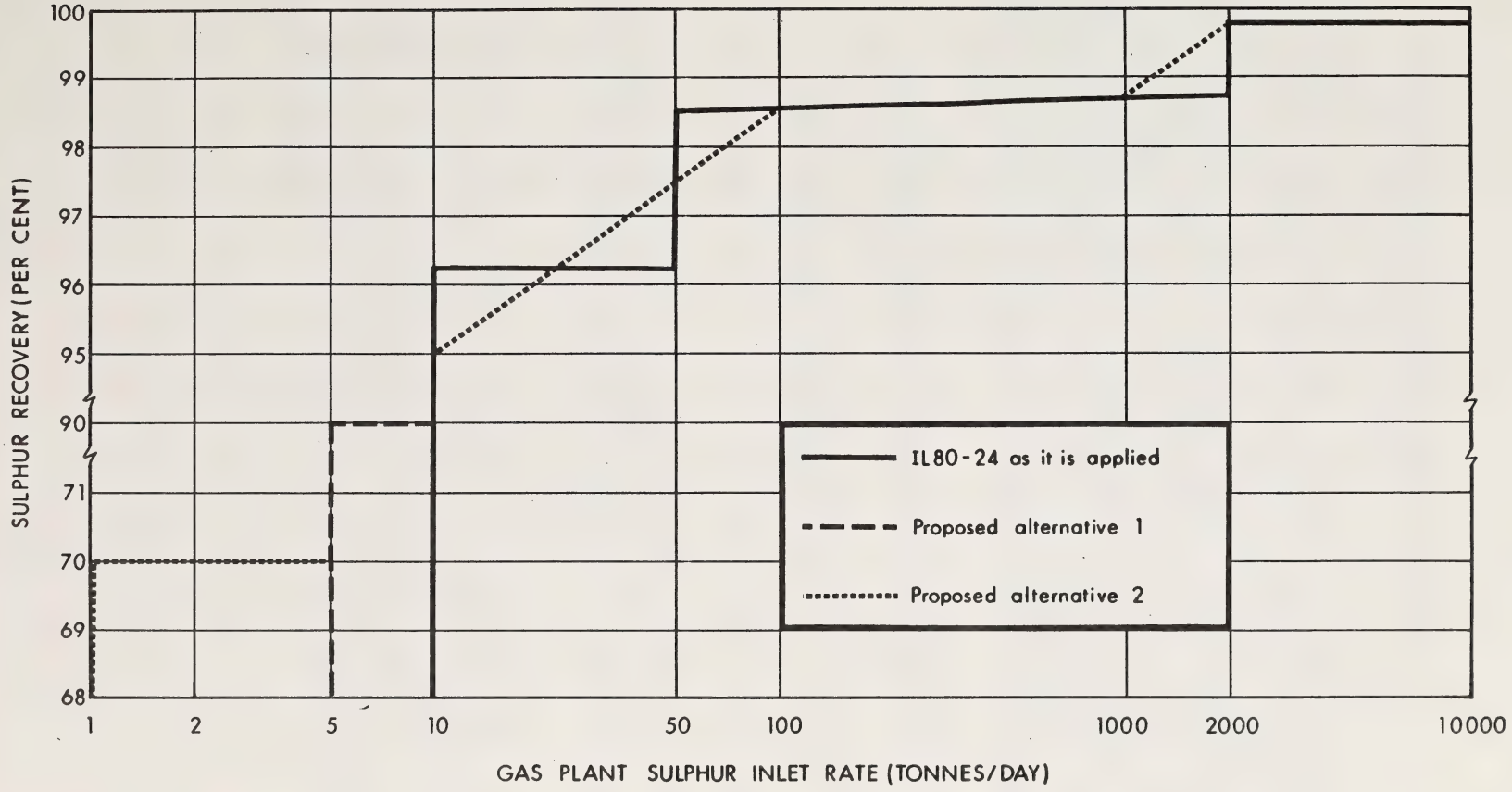

FIGURE 5 - 1 CURRENT AND PROPOSED SULPHUR RECOVERY REQUIREMENTS

6 PLANT EXPANSIONS, PRODUCTION FORECAST INCREASES, AND EXTENSIONS OF LIFE OF SCHEME

With respect to expanding plants and plants taking in new gas (either sour or sweet gas) from fields other than those already approved for the scheme, we considered whether a guideline intended for new plants should be applied, and if so, whether small expansions and short extensions of life should be exempt. We recognize that on the one hand, upgrading facilities to increase sulphur recovery efficiency at existing plants would cost considerably more than would be the case for a grassroots situation. On the other hand, without a mechanism to improve or upgrade sulphur recovery towards the new guidelines a plant could theoretically continue to operate with outdated technology, processing significant increments of gas from newly added wells and fields. We believe it is too difficult to forecast whether a particular case arising in the future should be required to meet new plant guidelines or not; however, as a set of checkpoints the task force suggests the following:

(i) if a plant's H_2S handling capacity is to be increased by more than 25 per cent (compared to the capacity at the time the new guideline is issued), or

(ii) if the forecast H_2S production over the life of a scheme is to be increased by more than 25 per cent, or

(iii) if the economic life of the scheme is increased by more than 50 per cent,

and when such occurrences are due to new gas from fields other than those already approved for the scheme, the ERCB should require application of the new plant guidelines unless the plant operator can demonstrate to the ERCB's satisfaction that in the particular case, the new plant guidelines should not be required.

Unanswered in (ii) and (iii) above is the question of how to administer the rules, that is, how to set up a relatively simple baseline to be used to compare gas production forecast and economic life of a scheme. Forecasts of gas production and economic life are frequently proven to be inaccurate. Consequently, we recommend that as applications to tie in new gas are received by the ERCB, judgemental comparisons of gas production forecast and economic life, without and with the new gas, are likely to be the most appropriate and administratively straightforward determants of applicability of the new guidelines.

We considered whether or not field boundaries should continue to be used for delineating the area from which additional wells may be tied in without reviewing sulphur recovery requirements for a plant. If field boundaries are not used to make a distinction between new gas and old gas, we believe that yet a more detailed program whereby gas production forecasts and determination of remaining life expectancy of most, if not all, existing schemes would be necessary at the outset. Any extensions past these bases would then be subject to rules covering expansions, production forecast increases, and life extension similar to those listed above. We believe that such a program would be unnecessarily detailed and burdensome, and would likely not achieve any more in the way of emission reduction than the current approach. Although the current approach toward distinguishing new gas from old gas could be continued, we believe that more work is required in this area to better define the criteria and process that will be used for assessing existing plant expansions and modifications.

APPENDIX A

ENERGY RESOURCES CONSERVATION BOARD
AND
ALBERTA ENVIRONMENT

SPECIFICATIONS FOR A REVIEW OF ALBERTA'S SULPHUR RECOVERY REQUIREMENTS FOR SOUR GAS PLANTS

A OBJECTIVE

Review the guidelines for sulphur recovery at gas processing plants, IL 80-24, to determine whether they are appropriate having regard for changes in technology and economics, and for sulphur recovery requirements in other jurisdictions.

B PROCESS TO BE USED

1 ERCB and AE will develop and distribute draft terms of reference for the study to all interested parties.

2 Industry and special interest groups will review the draft terms of reference and provide comments.

3 ERCB and AE will, as appropriate, meet with those providing additional input to ensure the concerns are understood.

4 ERCB and AE will finalize terms of reference.

5 Industry and the special interest groups would make submissions if they desire, which could suggest the way in which the task force work should be carried out, the processes to be looked at and other aspects of the study. This would be expected to take a couple of months, and may result in meetings and/or require the services of a consultant for the special interest groups.

6 Simultaneous with 5, an invitation for submissions would be sent, possibly through the co-operation of the CGPSA, to suppliers of sulphur recovery processes, and also to any others AE and ERCB considered appropriate. Submissions volunteered by individuals, groups, or individual companies would be accepted, but no general call for submissions would be made.

7 The task force will review the up-to-date technology respecting sulphur recovery, and the economics of applying that technology at gas plants in Alberta, including any submissions made according to items 5 and 6, and will propose a recommended revision to the current guidelines. The proposal will relate to all aspects of the requirements document IL 80-24.

8 The proposal will then proceed to a review stage and copies of the proposal will be provided to representatives of the industry, the special interest groups, and individuals from the public at large. These groups will select representatives who will meet along with ERCB and AE representatives to discuss the proposal and see if there are areas where agreement exists. If necessary, funding will be provided for experts to assist the special interest groups. If complete agreement is reached respecting the proposal, a report would go to the ERCB and AE indicating so, and the proposals would become policy. If there are areas where concensus is not reached, they will be referred to the ERCB and AE along with the positions of the various participants in the review and their supporting arguments for their positions.

9 One or more Board members from the ERCB and the Deputy Minister of the Environment and his associates will make up the policy or decision making committee. They will receive the proposal along with the conclusions of the review committee and make decisions on those matters where consensus was not possible. They may hold a meeting or informal hearing to listen to the arguments of the different participants in the review.

10 At the conclusion of the above process, the Board and Alberta Environment will compare sulphur recovery levels required under the new guideline with the levels currently being achieved at existing plants or groups of plants in all size ranges. If areas exist where there are significant differences, the Board and Alberta Environment will study the costs and benefits of applying the new requirements retroactively to some or all size ranges of plants. Upon its completion, this study will be discussed in a general way with public interest group and industry representatives.

C STEPS TO BE TAKEN AND APPROXIMATE TIMING

1 ERCB and AE appoint members of the task force. (Done)

2 Task force draft terms of reference of its study. (Done)

3 Participants in the review phase identify the individuals involved. (Done)

4 Task force provides draft terms of reference for its study to participants in the review phase, hears their comments, and adjusts the terms of its study appropriately. (Done)

5 Opportunity is provided for participants to make submissions to task force. (Not later than end of November 1985)

6 Task force study of technology and economics is completed - by March 1986.

7 Study is delivered to participants in the review phase - April 1986.

8 On-going discussions and meetings of participants in the review phase and completion of their conclusions respecting the task force proposals - by end of August 1986.

9 Conclusions and recommendations of participants in the review phase are sent to the policy committee - September 1986.

10 Meetings of policy committee as appropriate and final decision respecting revised recovery guidelines - by end of September 1986.

D TERMS OF REFERENCE FOR TASK FORCE RESPECTING SULPHUR RECOVERY REVIEW

1 Review technology and economics of sulphur recovery in Alberta for new plants and existing plants being expanded or about to process substantial volumes of sour gas from new sources. The review will include consideration of plants processing less than 10 tonnes per day of inlet sulphur.

2 Consider all processes emphasizing to a greater extent those where the technology is proven. Review technology and become familiar with it even if particular process is not economic in Alberta.

3 Consider alternative economic analysis techniques and employ those with most merit. Reasons for selection of a technique or techniques will be documented. Also, the task force's report will contain all raw cost data and economic parameters used in the analysis.

4 Consider past guidelines of Alberta and sulphur emission control strategies in other jurisdictions.

5 Develop several possible alternative control strategies, and choose best strategy (or more likely, two strategies) for detailed analysis.

6 On the basis of the technology study, economic calculations, and the best of the alternative control strategies, develop revisions to the guidelines as may be justified.

7 Estimate the benefit of imposing new guidelines for information purposes along with the costs, i.e. prediction of SO_2 emissions without and with new guidelines in effect and also the costs of adopting the new guidelines.

8 Review recommended guidelines in a general manner on basis of benefit-cost analysis. If benefits are very small for units of cost, reconsideration might take place with respect to certain plant groups or processes.

9 Finalize proposed guidelines including wording.

10 Issue report covering all phases of the work to participants in the review phase.

6 November 1985

APPENDIX B

ENERGY RESOURCES CONSERVATION BOARD AND
ALBERTA ENVIRONMENT
The Province of Alberta

Informational Letter
IL 80-24

TO: All Oil and Gas Operators
and Gas Processing Consultants

SULPHUR RECOVERY GUIDELINES
GAS PROCESSING OPERATIONS

New requirements have been set for sulphur recovery at new or expanding Alberta sour gas plants. The revised guidelines result from continuing investigations and communications involving the federal and provincial governments and the industry. They supersede the requirements previously established in 1971 as they are set out in the Board's Informational Letter IL 71-29 and in applicable parts of IL-OG 74-5.

While the new recovery efficiency requirements will be generally applicable, some variance may be appropriate in particular circumstances. For example, where there are overriding local environmental considerations, sulphur recovery may be required at small plants having a sulphur inlet rate of less than 10 tonnes per day (t/d). At plants with severe design constraints or operating conditions, a modest reduction in the required recovery level may be permitted if this appears to be environmentally acceptable. A decision to deviate from the normal requirement would not be made without opportunity for the input of persons who may be adversely affected.

New Plants

For plants commencing construction after 1 December 1980 and with approved inlet rates exceeding 10 t/d of sulphur, the expected minimum sulphur recovery for normal plant operating conditions shall be determined to the nearest 0.1 per cent from Figure 1. Figure 1 is intended to be applicable to plants processing good quality acid gas (i.e. acid gas containing more than 40 per cent hydrogen sulphide). An operator may apply for some relaxation if poor quality acid gas is to be processed. For small plants to be emitting less than 3 t/d of sulphur and processing acid gas barely within the good quality range, some relaxation may be permitted having regard for the cost and complexity of the equipment which would be required to achieve the recovery efficiency indicated in Figure 1. These and other exceptional cases will be considered individually.

The gas processing scheme approvals issued by the Board will stipulate a required quarterly average recovery of 0.3 per cent less than the recovery determined from Figure 1. This difference allows for operating periods during which the plant is experiencing start-ups and shut-downs or abnormal operating conditions.

Plant Expansion, Modification, or Life Extension

Plants being expanded or significantly modified will be assigned a sulphur recovery requirement on an individual basis having appropriate regard for the new requirements and such factors as the nature and extent of the expansion, environment protection, economics, and the forecast sulphur inlet rates. Similarly, where substantial new reserves of sour gas are to be processed in, and thus would extend the life of, a plant whose recovery efficiency was established under previous guidelines, the plant's sulphur recovery requirement would also be reviewed having regard for the same factors.

Existing Plants

Existing plants not included in the above categories remain subject to the sulphur recovery requirements stipulated in the respective approvals. As these stipulated requirements are expressed on a quarterly average basis, they are not to be reduced by the 0.3 per cent allowance mentioned above under the heading "New Plants".

An operator of an existing plant which is receiving gas from fields undergoing a decline in deliverability may apply for a reduction in the recovery efficiency requirement. The decision on an application of this type would be based on such relevant considerations as environmental impact, sustainable plant throughput, plant turndown ratio, and sulphur recovery efficiency experience at the plant.

ISSUED at Calgary, Alberta on 4 November 1980.

Alberta Environment

E. E. Kupchanko
Assistant Deputy Minister

Energy Resources Conservation Board

G. J. DeSorcy
Vice Chairman

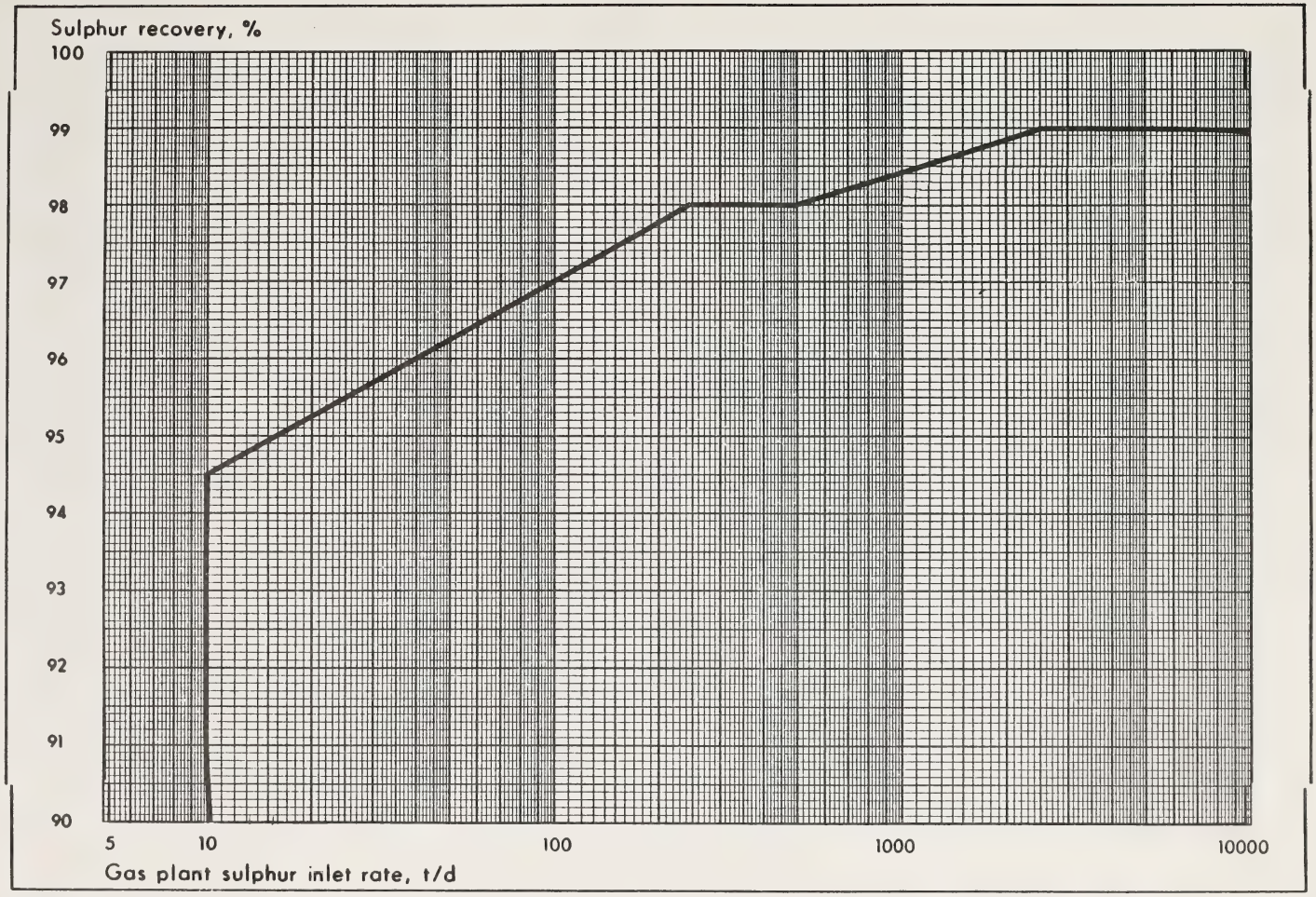

FIGURE 1 ALBERTA GAS PLANT - SULPHUR RECOVERY REQUIREMENT [1]

[1] At normal operating conditions. Deduct 0.3% for quarterly average requirement.

APPENDIX C

APPENDIX C SULPHUR RECOVERY AND TAIL GAS CLEAN-UP PROCESS DESCRIPTIONS

Primary Processes

- Modified-Claus Process

The Modified-Claus process is based on the chemical reaction of H_2S and SO_2 to form elemental sulphur. The stoichiometric ratio of H_2S to SO_2 for the reaction is 2:1. Various configurations of the front end of the process have been designed to produce the 2:1 ratio of H_2S and SO_2. In the straight-through configuration, the acid gas stream containing H_2S and CO_2 enters the reaction furnace along with the correct amount of air to oxidize one-third of the H_2S to SO_2 in the free-flame reaction. The straight-through configuration is typically used for acid gas that contains 50 to 100 per cent H_2S. Other configurations such as split-flow, split-flow with feed preheat, and sulphur recycle are used when the acid gas contains less than 50 per cent H_2S. The Modified-Claus process is not well-suited to very lean acid gas (less than 15 to 20 per cent H_2S) because the large amount of inert CO_2 inhibits the stable combustion of the acid gas stream.

In all of the above configurations, the process is essentially the same after the reaction furnace. The process gases are cooled in a waste heat boiler and condenser to condense the sulphur vapour that is formed in the reaction furnace. Steam is produced in the waste heat boiler and liquid sulphur is drawn off the condenser. The process gases are then reheated to a temperature above the sulphur dewpoint. The conversion of H_2S and SO_2 to sulphur continues in the first stage of catalytic conversion as the process gases pass through a bed of activated alumina catalyst. The process gas is then cooled once again to condense sulphur vapour formed in the first stage of catalytic conversion. Plants typically have 2 or 3 stages of process gas; reheat, catalytic conversion, and sulphur condensation. By operating each stage of catalytic conversion at a temperature lower than the preceding stage and removing produced sulphur in between, overall sulphur recovery is increased with each stage.

Under optimum operating conditions and treating good quality acid gas, rich in H_2S, the Claus process can be expected to achieve sulphur recovery levels in the order of 96 per cent from 2 stages of conversion and approaching 98 per cent from 3 stages of conversion. Expected levels of sulphur recovery decrease with decreasing H_2S concentration in the acid gas feed.

Claus plant capital costs increase with increasing sulphur inlet and also with increasing acid gas volume (ie, decreasing H_2S/CO_2 ratio). Costs for 2-stage Claus plants shown below illustrate the change in plant cost with sulphur inlet and acid gas quality.

Sulphur Input (t/d)	H_2S/CO_2	Capital Cost (10^6 $)
100	80/20	4.9
100	50/50	5.3
100	15/85	7.5
1000	80/20	25.0
1000	50/50	32.0
1000	15/85	51.0

The addition of a third stage of catalytic conversion to recover additional sulphur typically results in a 12 to 15 per cent increase in capital cost. The Claus reaction is exothermic so Claus plants operating with rich acid gas feed are net producers of steam which may be used outside of the sulphur plant.

- COPE (Claus Oxygen-based Process Expansion)

This process is a modification to the conventional Claus process wherein oxygen is substituted for all or part of the combustion air requirements. This substitution reduces the amount of inert gases that would pass through the process enabling the design of smaller, less costly sulphur plant vessels and at the same time, increasing sulphur recovery efficiencies by 0.5 to 0.8 per cent. COPE also has application in the debottlenecking of existing sulphur plants to increase capacity. The use of this technology could also have a significant effect on the cost of tail gas clean-up by reducing the volume of tail gas to be treated.

The process is based on the design of the acid gas burner and reaction furnace, which accomplish the mixing and combustion of the acid gas stream, oxygen and air, and a recycle process gas stream. A recycle blower returns part of the process gas from the first sulphur condenser to the reaction furnace to maintain the reaction furnace temperature at a tolerable level.

COPE has operated successfully for approximately 1 year in its first commercial application which was the expansion of an existing refinery sulphur plant. The economics of using the COPE process in a new sulphur plant/subdewpoint tail gas clean-up combination are essentially the same as using conventional Claus technology with subdewpoint tail gas clean-up. The reduced capital cost associated with the smaller process equipment with COPE is approximately offset by the capital cost for the air separation unit necessary as the oxygen source. By-product nitrogen from the air separation unit and recoverable CO_2 from the tail gas are benefits of using COPE to which some value could be attributed in certain instances.

- Linde Claus Plant Oxygen Enrichment

This enhanced combustion technology utilizes the addition of oxygen to the combustion air blower discharge of a conventional Claus plant to reduce the volume of inert nitrogen passing through the sulphur plant. In H_2S-rich acid gases, the amount of oxygen substituted for air is limited by thermal considerations in the reaction furnace. In lean acid gas cases, the substitution of oxygen enhances the Claus reaction kinetics by raising the reaction furnace temperature.

With this process, equipment modifications to an existing plant or additional equipment necessary for a new plant is essentially only the air separation unit.

- MCRC (Mineral and Chemical Resource Company)

The MCRC process is a variation of the Modified-Claus process wherein H_2S and SO_2 are reacted catalytically at temperatures below the dewpoint of the produced sulphur vapour. Allowing the catalytic conversion to occur at a temperature below the sulphur dewpoint enhances the conversion of H_2S and SO_2 to sulphur because the reaction is favoured at lower temperatures and because the sulphur formed as a product of the reaction is immediately removed from the reacting medium (ie, H_2S and SO_2 react in the vapour phase to form elemental sulphur which is adsorbed onto the catalyst as a liquid).

The front section of the MCRC process is similar to the Modified-Claus process, consisting of a reaction furnace in which one-third of the H_2S in the feed is oxidized to SO_2, followed by a waste heat boiler and then one conventional Claus stage consisting of reheat, catalytic conversion, and condensation. In this stage, the catalytic conversion occurs at a temperature above the sulphur dewpoint. Following this section of the process are two or three subdewpoint converters and sulphur condensers.

Operating the converters at subdewpoint temperatures causes the produced sulphur to condense immediately and be adsorbed onto the catalyst. The catalyst must therefore be periodically regenerated to remove the adsorbed sulphur. Catalyst regeneration is accomplished by reheating the process gas stream from the condenser following the conventional Claus converter to a temperature sufficient to vaporize liquid sulphur adsorbed onto the catalyst. The sulphur-laden gas is then cooled in a condenser to remove the sulphur. The process gas then passes through one or two more converters operating at subdewpoint temperatures. Once the catalyst in a subdewpoint converter has been regenerated it is cooled and returned to subdewpoint adsorption while the next converter is regenerated. A

slight drop in sulphur recovery accompanies the switching of the converters in the 3-converter system because of the time required to cool the regenerated catalyst to a subdewpoint temperature. The drop in efficiency is of short enough duration that the 3-converter process can achieve an average recovery level above 99 per cent. The temporary drop in efficiency is not seen with the 4-converter process because of the additional subdewpoint converter. Design recovery levels as high as 99.5 per cent can be achieved with the 4-converter process. The range of design recovery levels allowing for variation in acid gas quality is approximately 97 to 99 per cent for 3 converters and 98.5 to 99.5 for 4 converters.

The first commercial scale MCRC plant was built in 1979 to process 1100 t/d of inlet sulphur. Seven MCRC plants have been built since, the smallest designed for 13 t/d of inlet sulphur.

Capital cost of a 3-converter MCRC process is said to be approximately 7 per cent higher than an equivalent conventional Claus plant. The capital cost of a 4-converter MCRC unit would be about 23 per cent higher than the cost of a conventional 3-stage Claus plant. Operating utility rates would be similar to a conventional Claus plant.

- Selectox/Recycle Selectox

The Selectox process is a modification of the Claus process which eliminates the front end reaction furnace. Acid gas and air are heated to the reaction temperature and reacted over the Selectox catalyst to oxidize one-third of the H_2S to SO_2. The Selectox reactor is followed by a condenser to remove the sulphur formed in the Selectox reactor and then by one or two conventional Claus stages consisting of reheat, catalytic conversion, and condensation. In order to limit the temperature in the Selectox reactor to a level suitable for the use of carbon steel, the amount of heat produced by the exothermic Claus reaction is controlled by limiting the H_2S concentration in the acid gas feed to the reactor to 5 per cent. In cases where the acid gas to be processed contains more than 5 per cent H_2S, the Recycle Selectox process is used. In this process, a stream of process gas lean in H_2S is taken from the first sulphur condenser and recycled to the Selectox reactor. The recycle stream is mixed with the acid gas feed to maintain an H_2S concentration in the Selectox reactor not exceeding 5 per cent.

The Selectox and Recycle Selectox processes are particularly well-suited to acid gas streams lean in H_2S and are capable of achieving higher recovery levels with lean acid gas than the Modified-Claus process. Typically, for acid gas containing 1 to 5 per cent H_2S, a 3-stage Selectox process would achieve a recovery level of

85 to 90 per cent. For acid gas containing 8 to 12 per cent H_2S, a 2-stage Recycle Selectox process would be expected to achieve 88 to 90 per cent. A 3-stage Recycle Selectox process would achieve a recovery level of 94 to 96.5 per cent on acid gas containing 10 to 40 per cent H_2S.

Capital costs of the Selectox and Recycle Selectox process range from 75 to 90 per cent of equivalent Claus plants with the greater cost differential occurring with leaner acid gas feeds. Operating costs are marginally higher than for a Claus plant.

- Stretford Sulphur Removal

In the Stretford Sulphur Removal Process, H_2S is selectively absorbed into the Stretford solution and oxidized directly to elemental sulphur. The process is capable of reducing H_2S concentrations to very low levels so that no secondary off-gas treatment is required.

The Stretford liquor is an alkaline solution of sodium carbonate/bicarbonate, sodium vanadate, and the sodium salt of anthraquinone disulfonic acid. The solution initially converts H_2S to the HS^- ion which then reacts with oxidized vanadium in the solution to form elemental sulphur. The vanadium in solution is regenerated by oxidizing with air.

Acid gas is contacted with the Stretford solution with the H_2S being absorbed. The H_2S-rich Stretford solution then passes to a reaction tank where the necessary time (several minutes) is provided for the reaction of the HS^- ion with vanadium to go to completion. The sulphur-rich Stretford solution then enters an oxidizer for aeration to regenerate the vanadium and to float the suspended sulphur particles that have been formed to a froth on top of the solution. At this stage the solution has been regenerated and is returned to the absorber. The sulphur froth is removed from the oxidizer for further treatment to produce a moist sulphur cake or molten sulphur.

The Stretford process has been used extensively as a tail gas clean-up process. It has also had application as a sulphur recovery process in treating acid gas streams from a sweetening process. More recently, it has been developed for use in high-pressure service for sour gas sweetening. The largest unit so far has been built to recover approximately 70 t/d of sulphur.

Capital and operating costs for the Stretford process are estimated to be similar to the Lo-Cat process. Operating costs rise as the amount of H_2S being treated increases so the process is best-suited to streams containing smaller amounts of H_2S.

- Lo-Cat Hydrogen Sulphide Oxidation

The Lo-Cat process uses an aqueous scrubbing solution of a chelated iron compound to absorb H_2S and oxidize it to elemental sulphur. The sulphur forms as small solid particles which remain suspended in the Lo-Cat solution until they grow large enough to settle. Lo-Cat solution is regenerated by aeration to oxidize the iron in solution to its active state.

Sour gas or acid gas (process can be used to treat either) is contacted with the Lo-Cat solution in a high- or low-pressure absorber. H_2S is absorbed into the solution and oxidized to elemental sulphur. The reduced solution containing the sulphur particles flows from the absorber to an oxidizer vessel where the sulphur settles to the cone-shaped bottom. Also in the oxidizer, air is sparged through the Lo-Cat solution to oxidize the iron in solution to return it to its active state. (In the Auto-Circulation configuration for treating acid gas streams, the absorber and oxidizer vessels are combined into one.) Sulphur is drawn off the bottom of the oxidizer as a slurry (15 per cent sulphur by weight and 85 per cent Lo-Cat solution). For plants producing less than 0.5 t/d of sulphur, the slurry is usually considered to be a waste product and is disposed of. For plants producing 0.5 to 2 t/d of sulphur, some type of dewatering facility may be warranted to recover part of the Lo-Cat solution from the sulphur slurry. For plants larger than 2 t/d, the value of the sulphur may warrant a sulphur melting facility in which the sulphur is recovered and no catalyst solution is lost from the system.

The process is very efficient in conversion of H_2S to sulphur and is designed to achieve 99.95 per cent in the treatment of ordinary amine effluents.

There is no lower limit on the volume or H_2S content of the feed stream to the Lo-Cat process. It is therefore particularly well-suited to small applications. The largest plant designed to date will process some 37.5 t/d of sulphur.

The first commercial applications of Lo-Cat occurred in the late 1970s at refineries and chemical plants. The first application to sour gas processing was in 1983. Since then, some six Lo-Cat units have been installed for sour gas treating and several more are in the design stage.

Capital costs for the Lo-Cat process vary with sulphur inlet and to some extent with the H_2S concentration in the feed gas. Costs for small auto-circulation units range from $475 000 for a 1 t/d plant to $2.5 million for a 10 t/d plant. Chemical costs make up the largest part of Lo-Cat variable operating costs which might range from more than $300/t of inlet sulphur for very small plants (less than 1 t/d) to $100/t of inlet sulphur for a large plant (10 t/d).

- Kellog Oxydesulphurization (ODS)

ODS is a new process that has been successfully developed to a pilot scale stage but has yet to be used in a commercial application. The process can be used to remove H_2S from either sour gas or acid gas streams.

In the ODS process, feed gas is contacted with an aqueous solution which selectively absorbs the H_2S and oxidizes it to elemental sulphur. The ODS reactor vessels operate at approximately 2000 kPa pressure and 150°C. At these conditions, the sulphur is formed as a liquid and is separated from the circulating solution gravimetrically. The ODS solution is regenerated by oxidation with either oxygen or air.

H_2S removal and conversion to sulphur is essentially complete with the ODS process.

ODS capital costs increase only slightly as H_2S or CO_2 concentrations increase up to 10 per cent. Capital costs are about $2 million for a 20 t/d unit (10 per cent H_2S in feed) and $3 million for an 80 t/d unit (10 per cent H_2S in feed). Operating costs vary from $60/t of processed sulphur for a 2 t/d plant with 1 per cent H_2S in the feed to $15/tonne of processed sulphur with 5 per cent H_2S in the feed.

- Citrate

Originally developed for flue gas desulphurization, the Citrate process uses an aqueous solution of citric acid and sodium citrate to absorb SO_2. The citrate solution containing SO_2 is reacted with H_2S to form elemental sulphur and regenerate the solution.

As a primary sulphur recovery unit, the process involves the combustion of part of the acid gas feed stream to oxidize H_2S to SO_2. The hot gas is then cooled by water quench and contacted with lean citrate solution. The solution absorbs SO_2 from the process gas which leaves the absorber with a very low remaining SO_2 content. The SO_2-rich citrate solution is regenerated by contacting with H_2S which has by-passed the combustion step at the front end. The H_2S reacts with the SO_2 in solution to form solid sulphur particles (5-15 microns in size). In a flotation tank, air is bubbled through the citrate solution to float the suspended sulphur particles into a froth on the surface. The froth, containing 10 per cent sulphur by weight, is passed through a sulphur melter to separate liquid sulphur from the citrate solution. A by-product of the Citrate process is Glauber's salt. Approximately 1.5 per cent of the sulphur in the SO_2 fed to the citrate plant is converted to sulphuric acid through side reactions. This is neutralized by the addition of caustic (sodium hydroxide) which forms sodium sulphate. This is purged from the system and forms Glauber's salt crystals after evaporative cooling.

The process is designed for essentially complete removal of SO_2 from waste gas streams.

The process has not yet been applied in the sour gas processing industry.

No capital or operating cost information is available for the Citrate process.

- Unisulf

The Unisulf process uses Unisulf solution to selectively absorb and oxidize H_2S to elemental sulphur. The process could be used to treat a raw sour gas stream or an acid gas stream. Unisulf solution is regenerated by contacting with air which also serves to float the elemental sulphur particles to the surface of the oxidizer vessel. The sulphur froth is then further treated by filtration or centrifuging to separate the sulphur from the Unisulf solution. Separated sulphur is melted for further purification.

The process has a high H_2S absorption and conversion efficiency. Typically, treated gas leaving the absorber would contain less than 1 ppm H_2S.

The Unisulf solution experiences no chemical degradation during use, thus eliminating the need for a purge stream. The only loss of solution from the system is the physical loss associated with sulphur separation and removal.

Mechanical equipment required for the Unisulf process is similar to the Stretford process and the two solutions are interchangeable. Unisulf has been commercially demonstrated.

Capital and operating costs are estimated to be similar to the Lo-Cat process. As with the other chemical processes, operating costs increase as the sulphur production rate increases. Unisulf is therefore best-suited to small applications.

- Sulfint

The Sulfint process removes H_2S from sour natural gas or acid gas by selective absorption followed by oxidation of the H_2S to elemental sulphur in an aqueous scrubbing solution. The active component of the Sulfint solution is a chelate-bound iron compound. The solution is regenerated by oxidizing with air to return it to its active state. Also in the oxidizer vessel, the formed sulphur particles agglomerate and then settle to the bottom of a settling tank. A sulphur slurry of 5 per cent sulphur by weight is drawn off the bottom of the settling tank and pumped to a decanter where most of the Sulfint solution is recovered. The recovered solution is treated in a reverse osmosis unit to separate water and dissolved salts (sulphate, carbonates, and alkalies). The decanted sulphur may be further purified by water washing and melting.

The process is designed to achieve approximately 99.9 per cent conversion of H_2S to sulphur.

The process is most suitable for gas streams containing small quantities of H_2S. It has been applied commercially twice in Europe, the largest application being an 18 t/d plant, although neither application has been for treating natural gas.

Capital costs for the Sulfint process range from $400 000 to $850 000 for a 1 t/d plant. Operating costs are estimated to be similar to the Lo-Cat process.

- Budra One-Step Desulphurization

The Budra process is newly developed and has been tested on a pilot scale at a sour gas plant in Alberta. It has not yet been demonstrated on a commercial scale.

The process uses a chemical catalyst impregnated on a standard alumina carrier that converts H_2S directly to elemental sulphur which is then adsorbed onto the catalyst. When fully loaded, the catalyst bed is regenerated by heating with hot sweet gas. Adsorbed sulphur is driven off the catalyst as a liquid and collected.

The Budra process is designed to convert essentially 100 per cent of the H_2S in the gas being treated to sulphur. The catalyst is also capable of removing CO_2 from the gas stream by adjusting the length of time the catalyst bed operates prior to regeneration. The process would be capable of treating a sour natural gas stream or an acid gas stream.

No cost information is available on the Budra process.

- Stauffer Sulphur Recovery

SSRP is an aqueous Claus process that uses an alkali-metal phosphate-buffered scrubbing solution to absorb SO_2 from a gas stream. The solution is regenerated by contacting with H_2S which reacts with the absorbed SO_2 to form elemental sulphur. SSRP has been developed to the stage of a commercial-scale demonstration plant for testing purposes. The process is highly efficient, being designed to achieve 99.9 per cent sulphur recovery.

In application of the SSRP to acid gas treating, the acid gas stream is contacted with SO_2-rich solution in an absorber. H_2S reacts with the SO_2 dissolved in solution to form solid elemental sulphur. Excess H_2S is provided for the reaction to ensure complete regeneration of the scrubbing solution (ie, no SO_2 remains in the solution). The acid gas stream leaving the absorber therefore will contain some H_2S. The elemental sulphur produced leaves the absorber as solid particles

suspended in the regenerated solution. This stream is heated to melt the sulphur which is then separated from the scrubbing solution. The vent stream from the absorber is incinerated to convert the remaining H_2S to SO_2 which is then absorbed by the lean scrubbing solution. The SO_2-rich scrubbing solution is then recirculated for contacting with the acid gas feed stream. A purge stream is taken from the circulating solution to remove sulphate which would otherwise concentrate in the solution. The purge stream is cooled to produce sodium sulphate decahydrate, also known as Glauber's salt.

One commercial-scale (32 t/d) SSRP demonstration plant was constructed and has operated since 1984.

The SSRP process is said to show a significant capital cost advantage and marginal operating cost advantage over a Claus plant with tail gas clean-up that would achieve a sulphur recovery level of greater than 99.5 per cent. For recovery levels in the 98 to 99 per cent range, capital and operating costs for SSRP are approximately equal to a Claus plant with subdewpoint tail gas clean-up. For recovery levels in the 95 to 96 per cent range, SSRP capital and operating costs are slightly higher than the costs for a Claus plant alone.

- Integrated UCAP

The Integrated UCAP process is a modification of UCAP SO_2 absorption technology whereby UCAP is integrated into a Claus plant. The process is well-suited to acid gas streams lean in H_2S where the conventional Claus process would not function well. In the Integrated UCAP process the raw acid gas stream is heated, mixed with a recycle stream of SO_2 in a ratio of 3 to 1 (H_2S to SO_2) and enters the catalytic reactor where the Claus reaction occurs to produce elemental sulphur. Approximately two-thirds of the H_2S and almost all of the SO_2 is reacted. The gas is then cooled to condense the sulphur that has been produced. The process gas leaving the condenser is mixed with fuel and excess air and burned to completely oxidize remaining H_2S and any other sulphur compounds to SO_2. This tail gas is then cooled in a waste heat boiler and by water quench to remove water. Following cooling, the gas is contacted with lean UCAP triethanolamine solvent which selectively absorbs SO_2 while rejecting CO_2. Vent gas from the absorber contains less than 250 ppm SO_2. The rich UCAP solvent is regenerated by thermally stripping the SO_2. The recovered SO_2 is then recycled to the front of the Claus plant for mixing with the raw acid gas feed. A small portion of the SO_2 reacts in the UCAP solvent to form heat stable salts, primarily sulphates, thiosulphates, and thionates which are not removed by thermal stripping. It is necessary to remove these salts by a purge stream to prevent reduction of the capacity of the solvent to absorb SO_2. A slipstream of lean solvent

is treated in an ion exchange process to separate the salts for disposal from the solvent which is returned to the system. Fabrication must be of stainless steel for all vessels downstream of the oxidizer because of exposure to hot, wet SO_2.

The Integrated UCAP process is designed to achieve sulphur recovery levels above 99.9 per cent.

One commercial-scale unit was built in 1979 to treat amine acid gas at a refinery.

Limited information on capital and operating costs suggests that the Integrated UCAP process would cost somewhere in the order of 50 per cent more to build and operate than a conventional 2-stage Claus plant.

Tail Gas Clean-up Processes

- Sulfreen

The Sulfreen process is an extension of the Claus reaction at a temperature below the sulphur dewpoint. The 125 to 150°C operating temperature of the Sulfreen process promotes the reaction of H_2S and SO_2 to form sulphur to the extent that the overall design sulphur recovery level (Claus plus Sulfreen) can exceed 99 per cent. Typically, the SO_2 content of incinerated Sulfreen tail gas is in the order of 1000 to 1500 ppm.

The process operates as a batch process with two or three Sulfreen reactors alternating between adsorption and regeneration. The sulphur produced in the Sulfreen reactors is in the liquid phase and is adsorbed onto the Sulfreen catalyst while the reactor is in the adsorption mode. When the catalyst is loaded with sulphur, it is regenerated by a stream of hot gas which vaporizes the sulphur and removes it from the catalyst. The hot gas stream containing the sulphur vapour is then cooled to condense the sulphur vapour. The regeneration gas is contained in a closed loop of heating, desorbing sulphur from the catalyst being regenerated, cooling to condense the sulphur, and then reheating. When the catalyst is free of sulphur it is treated with a small amount of acid gas to reduce sulphates that tend to form during adsorption. If not treated, the sulphate causes premature catalyst aging and loss of activity. Following desulphation, the Sulfreen reactor is cooled to its subdewpoint operating temperature and returned to the adsorption mode.

Sulfreen recovers all vapour phase elemental sulphur present in the feed and converts approximately 90 per cent of the H_2S and SO_2 to sulphur which is recovered. COS and CS_2 present in the Claus tail gas

are not considered to be recoverable in the Sulfreen process and typically account for about 50 per cent of the total sulphur losses from a Claus/Sulfreen system. Minimizing COS and CS_2 in the Claus plant tail gas through appropriate operating conditions can increase overall design sulphur recovery levels to as high as 99.5 per cent for a Claus/Sulfreen system.

The Sulfreen process has been applied commercially since 1970. Approximately 20 units are in operation in the gas processing industry, industry treating tail gas from Claus plants ranging in size from 20 to 2200 t/d of sulphur.

The capital cost of a Sulfreen unit is in the order of 35 to 50 per cent of a 2-stage Claus plant. The major operating costs associated with the Sulfreen unit is in the operation of the regeneration loop, ie, fuel gas for the heater and power for the blower, although much of the fuel gas energy is recovered through the production of low-pressure steam from the sulphur condenser. The unit can be designed to use an economizer installed in the incinerator flue gas stream to provide regeneration heat duty, thereby eliminating the fuel gas requirement. Annual operating costs are estimated to be 10 to 15 per cent of capital investment.

- Amoco Cold-Bed Adsorption (CBA)

The Amoco CBA process is similar to Sulfreen in that both are subdewpoint processes. Like Sulfreen, the CBA process continues the Claus reaction and is capable of increasing the overall design sulphur recovery level to 99 per cent or greater.

In the CBA process, catalyst regeneration is accomplished by diverting a slipstream of gas from the first converter of the Claus plant (gas temperature of 340 to 370°C) through the CBA reactor in the regeneration mode. The hot gas vaporizes the liquid sulphur adsorbed on the catalyst and is then cooled in the CBA regeneration condenser to condense the sulphur vapour. The regeneration gas is then returned to the second condenser of the Claus plant.

The first commercial-scale CBA unit began operating at Amoco's East Crossfield plant in 1976. Another eight CBA units have been built since 1976.

The capital cost of a CBA unit is approximately 35 to 50 per cent of the cost of a 2-stage Claus plant. Annual operating costs are estimated to be 10 to 15 per cent of capital investment.

- MCRC

The MCRC process is a subdewpoint process which may be used as a primary sulphur recovery unit or may be added to a Claus plant to treat the tail gas. MCRC process details are described in the preceding section dealing with sulphur recovery processes. For catalyst regeneration, the MCRC process directs the complete hot process gas stream from the front end of the plant through the regenerating converter. The sulphur-laden gas then passes through a condenser and then through the remaining subdewpoint bed(s) and condenser(s).

The MCRC process can increase the overall design sulphur recovery level of a Claus plant to 99 per cent or greater. As with the other subdewpoint processes, MCRC does not convert appreciable amounts of COS and CS_2 to sulphur so it is necessary to minimize the amount of these compounds in the feed to the subdewpoint converters in order to maximize the overall sulphur recovery.

The capital cost of an MCRC tail gas clean-up unit is some 35 to 45 per cent of the cost of a 2-stage Claus plant. Operating costs would be similar to other subdewpoint processes.

- Maxisulf

Maxisulf is a subdewpoint tail gas clean-up process that utilizes 2 catalytic converters, a sulphur condenser, and an inline burner to recover additional sulphur from Claus plant tail gas. By continuing the Claus reaction at subdewpoint temperatures, Maxisulf can increase the overall design sulphur recovery level to 98 to 99 per cent.

Maxisulf is distinct from other subdewpoint processes by the method of catalyst regeneration. While most of the Claus plant tail gas is passing through the subdewpoint adsorption bed, a slipstream is heated with an inline burner and used to desorb sulphur from the regenerating catalyst bed. This stream of hot sulphur-laden gas is cooled to condense the sulphur vapour and is then mixed with the tail gas entering the adsorption reactor.

Maxisulf was commercially demonstrated in a small test plant (5 t/d Claus plant) in 1982. Subsequent to that, units have been designed to treat tail gas from two 60 t/d Claus plants in Germany.

The capital cost of a Maxisulf unit is approximately 20 per cent of the associated 2-stage Claus plant. The main variable operating cost is for fuel to the inline burner used to heat regeneration gas. Part of the heat duty is recovered as low pressure steam from the sulphur condenser. Annual operating costs are estimated to be 10 to 15 per cent of the capital investment.

- IFP Clauspol 1500

The IFP Clauspol 1500 process uses a polyethylene glycol solvent to absorb H_2S and SO_2 from Claus plant tail gas and a dissolved catalyst (sodium salt of an organic acid) to promote continuation of the Claus reaction in the liquid phase. The process operates at a temperature of 120 to 122°C which is only slightly higher than the sulphur solidification temperature. Operating at this low temperature promotes the conversion of H_2S and SO_2 to sulphur. COS and CS_2 are partially hydrolysed to H_2S in the process which is then recoverable as sulphur.

Claus tail gas is contacted with the circulating solvent in a packed column absorber. The treated gas leaving the absorber is incinerated. Produced liquid sulphur is removed from the bottom of the absorber. Sodium in the solvent is slowly consumed through a side reaction that produces sodium sulphate. This necessitates a constant catalyst make-up. Also, because the sodium sulphate produced is insoluble in the solvent, it deposits on the absorber tower packing. This requires shutdown of the absorber after approximately 2 years of operation to wash the sodium sulphate from the packing.

The Clauspol 1500 process is capable of increasing design sulphur recovery levels to 99.5 per cent. Remaining sulphur compounds in the Clauspol unit off-gas are approximately 1500 ppm.

The process has been designed for some 35 units treating tail gas from Claus plants ranging in size from 30 to 800 t/d.

The capital cost of the IFP Clauspol process is approximately 60 to 70 per cent of the cost of the associated 2-stage Claus plant. Annual operating costs are estimated to be 10 per cent of capital investment.

- SCOT

In the SCOT (Shell Claus Offgas Treating) process, all sulphur compounds contained in the Claus plant tail gas including COS and CS_2 are hydrogenated and hydrolysed to H_2S. This is accomplished by heating the tail gas and reacting it with a reducing gas over a Cobalt-Molybdenum catalyst bed. The gas is then cooled to remove water and contacted with an H_2S-selective solvent which absorbs almost all of the H_2S. The treated gas leaving the absorber contains about 200 to 500 ppm of H_2S.

The rich amine is regenerated by heating to strip the H_2S which is returned to the front of the Claus plant for processing.

The SCOT process was developed in the early 1970s and there are now some 100 plants in operation treating tail gas from Claus plants ranging in size from 4 to 2100 t/d.

The addition of a SCOT unit to treat Claus plant tail gas can increase the overall design sulphur recovery efficiency to greater than 99.8 per cent.

The capital cost of a SCOT unit is in the order of 80 to 100 per cent of the cost of the associated 2-stage Claus plant. Annual operating cost of the process is estimated to be 10 per cent of capital investment.

- BSR/MDEA (Beavon Sulphur Removal)

The BSR/MDEA process operates similarly to the SCOT process. Claus plant tail gas is heated and reacted with a reducing gas over a Cobalt-Molybdate catalyst bed to convert all sulphur compounds present in the gas to H_2S. The gas stream is then cooled by a water quench and contacted with an MDEA (methyldiethanolamine) solution. The MDEA solution selectively absorbs H_2S from the gas stream. Treated gas leaving the absorber is incinerated, after which it typically contains less than 250 ppm SO_2. Absorbed H_2S is stripped from the MDEA solution by heating and returned to the front of the Claus plant.

Overall design sulphur recovery with a 3-stage Claus plant followed by BSR/MDEA is greater than 99.9 per cent. The process is used in four commercial applications.

The capital cost of a BSR/MDEA unit is approximately 80 to 100 per cent of the cost of an associated 2-stage Claus plant. Annual operating costs are estimated to be 10 per cent of capital investment.

- BSR/Stretford

This process combines BSR hydrogenation/hydrolysis technology with Stretford sulphur recovery technology. As with the BSR/MDEA process, Claus tail gas is heated and reacted with a reducing gas over Cobalt-Molybdate catalyst to convert all sulphur compounds to H_2S. The gas is then cooled and contacted with Stretford solution. H_2S is absorbed into the Stretford solution and oxidized to elemental sulphur in the solid phase (see Stretford Sulphur Removal Process described earlier in this Appendix). Sulphur is recovered by flotation and is further treated by centrifuge and/or melting to recover Stretford solution and purify the sulphur.

Design sulphur recovery levels up to 99.99 per cent can be achieved by treating the tail gas from a 3-stage Claus plant with a BSR/Stretford unit. Typically, treated tail gas from a BSR/Stretford unit contains about 1 ppm H_2S and would not require incineration.

Some 50 BSR/Stretford plants have been built and operated mainly at refineries.

The capital cost of a BSR/Stretford process is 90 to 120 per cent of an associated 2-stage Claus plant. Operating costs are slightly less than the costs of the solvent absorption tail gas clean-up processes.

- BSR/Unisulf

This process operates in the same manner and with the same equipment as BSR/Stretford, the only difference being that a proprietary solution called Unisulf replaces the Stretford solution. The Unisulf solution performs the same function as Stretford, that of absorbing H_2S and oxidizing it to elemental sulphur (see Unisulf Process described earlier in this Appendix). The performance of Unisulf solution is equivalent to the Stretford process with respect to sulphur recovery (ie, capable of increasing design recovery to 99.99 per cent). The advantage of the Unisulf solution is that there is no formation of heat-stable salts in the solution thereby eliminating the need for a purge stream and reducing the requirement for chemical addition to the system.

The Unisulf process has been demonstrated on a commercial scale.

The capital cost of a BSR/Unisulf unit would be similar to BSR/Stretford. Operating costs would be similar, possibly somewhat less for the BSR/Unisulf due to reduced chemical consumption.

- Sulften

In this process, Claus plant tail gas is heated and passed through a reaction vessel containing two catalyst beds which promote the hydrolysis of COS and CS_2 to H_2S and the reaction of SO_2 and hydrogen (reducing gas) to form H_2S. In natural gas installations, the hydrogen source is typically the substoichiometric combustion of sweet gas in the feed preheater. Following the hydrolysis and hydrogenation reactions the gas is cooled by water-quench to remove water vapour. The cooled gas is contacted with Sulften solvent (proprietary MDEA-base) in an absorber. The Sulften solvent selectively absorbs almost all of the H_2S from the gas. Treated gas leaving the absorber contains less than 10 ppm H_2S and does not require incineration. A small amount of CO_2 is also absorbed from the gas into the Sulften solvent. H_2S and CO_2 are stripped from the solvent by heating and are returned to the Claus plant for processing.

The overall design sulphur recovery level achievable with Sulften tail gas clean-up following a Claus plant is greater than 99.99 per cent.

The first commercial-scale Sulften unit has operated at a refinery since 1983 treating tail gas from a 43 t/d Claus plant.

The capital cost of a Sulften system is about 80 per cent of the cost of the associated 2-stage Claus plant. Operating costs are somewhat lower than with other similar processes, ie, conversion of H_2S and selective absorption, because of a 25 per cent reduction in utilities required by the Sulften system for solvent circulation and stripping. The reduction in incinerator fuel gas required due to running the incinerator in a standby mode only is also significant.

- BSR/Selectox

In this process, the BSR hydrogenation/hydrolysis unit is followed by a Selectox reactor. The gas stream containing the H_2S produced in the BSR unit is cooled by a water quench to remove water vapour. Air is then added to the stream and it is heated and passed through a bed of Selectox catalyst. Part of the H_2S is selectively oxidized by the air to SO_2 which then reacts with remaining H_2S to produce sulphur vapour. After reacting over the Selectox catalyst, the stream is cooled to condense the sulphur vapour that has formed. Approximately 80 per cent of the H_2S fed to the Selectox reactor is recovered as liquid sulphur from the condenser.

The BSR/Selectox process is designed to increase sulphur recovery levels to 98.5 to 99.5 per cent.

One commercial-scale BSR/Selectox unit has operated since 1978. The capital cost of a BSR/Selectox unit is about 45 to 50 per cent of an associated 2-stage Claus plant. Operating costs are said to be about one-half of the operating costs of subdewpoint processes and about one-quarter of the costs of H_2S absorption processes.

- Oxysulfreen

Oxysulfreen is a recently developed modification of the conventional Sulfreen process wherein all sulphur compounds present in the Claus tail gas feed to the unit are first converted to H_2S by hydrolysis and hydrogenation reactions. The gas is then cooled by a water quench to condense water vapour. The gas stream is reheated and mixed with a controlled amount of air prior to entering an oxidation reactor where one-third of the H_2S is catalytically oxidized to SO_2. Sulphur vapour formed in the oxidation reactor by the reaction of H_2S and SO_2 is removed in a condenser. The process gas then enters the conventional Sulfreen unit where it passes through two or three subdewpoint catalyst beds to continue the conversion of H_2S and SO_2 to sulphur.

The Oxysulfreen process is able to achieve a higher level of sulphur recovery than the conventional Sulfreen process by eliminating some of the sulphur losses associated with the straightforward subdewpoint

process. With conventional subdewpoint technology, sulphur losses occur because of COS and CS_2 in the feed, deviation from optimum H_2S/SO_2 ratio, and the presence of water vapour inhibiting the conversion of H_2S and SO_2 to sulphur.

The Oxysulfreen process is designed to increase overall sulphur recovery levels to 99.5 to 99.8 per cent.

The process has not been commercially demonstrated.

The capital cost of the Oxysulfreen process is approximately equal to the cost of the associated 2-stage Claus plant. Operating costs are higher than for conventional subdewpoint processes due to increased utilities consumption but are less than for processes that convert sulphur compounds to H_2S followed by solvent absorption.

- ULTRA (Ultra Low Temperature Reaction Adsorption)

This process, developed by Amoco, is an extension of the CBA tail gas clean-up process. As with the Oxysulfreen process, the Claus tail gas feed to the ULTRA unit is heated and passed through a hydrogenation/hydrolysis reactor to convert all sulphur species present to H_2S. The tail gas is then cooled by a water quench to remove water. H_2S stripped from the condensed sour water is mixed with the tail gas stream. One-third of the tail gas stream is heated, mixed with air, and passed through a reactor where the H_2S is catalytically oxidized to SO_2. After cooling to subdewpoint temperature, this gas stream and the stream containing the remaining two-thirds of the H_2S enter a conventional CBA reactor operating at subdewpoint temperature. As with the CBA process, liquid-phase sulphur is adsorbed onto the catalyst operating in the subdewpoint mode. When the catalyst is loaded with sulphur, it is regenerated by passing hot process gas from the outlet of the first catalytic reactor of the Claus plant through the subdewpoint bed to vaporize the adsorbed sulphur. The hot gas is cooled to condense the produced sulphur and is then returned to the Claus plant. After regeneration, the bed is cooled to subdewpoint temperature for the next adsorption cycle.

The ULTRA process is designed to achieve an overall sulphur recovery level of 99.7 per cent. ULTRA is able to achieve higher recovery than a conventional subdewpoint process because of the reduction of sulphur losses due to COS and CS_2 in the feed, the removal of water, and the ability to control the H_2S/SO_2 ratio entering the subdewpoint reactor.

The ULTRA process was pilot-tested in 1982 as a retrofit to an existing 22 t/d 2-stage Claus plant with a conventional CBA unit.

No capital or operating cost data are available on ULTRA.

- UCAP

The UCAP process uses a triethanolamine solvent to selectively absorb SO_2 from gas streams. In application as a Claus plant tail gas clean-up unit, Claus tail gas is first incinerated to convert all sulphur compounds to SO_2. The tail gas is then cooled, first in a waste heat boiler and then by a water quench to condense water vapour. The gas is contacted with the lean UCAP solvent which selectively absorbs almost all of the SO_2. The cleaned tail gas leaving the UCAP absorber typically contains less than 250 ppm SO_2. The SO_2-rich solvent is stripped thermally and the SO_2 is recycled to the Claus plant for processing. While almost all of the SO_2 is recovered from the rich solvent by the stripping process, a small amount reacts in the solvent to produce heat stable salts, principally sulphates, thiosulphates, and thionates. A build-up of these salts will result in lost capacity of the solvent so it is necessary to remove them by a purge stream. A slipstream of lean solvent is passed through an ion exchange process whereby the heat stable salts are removed and discarded and the solvent is returned to the process. Most of the UCAP process vessels must be constructed of stainless steel because of the exposure to hot, wet SO_2.

The UCAP process is designed to increase sulphur recovery levels to greater than 99.9 per cent.

UCAP has been successfully bench-scale tested with no commercial-scale application to date as a tail gas clean-up process. A commercial-scale Integrated UCAP unit was installed in 1969 to treat amine acid gas at a refinery (see Integrated UCAP Process in Section 3.2).

UCAP is said to be economically competitive with other tail gas clean-up processes capable of reducing the SO_2 content in the tail gas to 250 ppm.

- Wellman-Lord

The W-L process uses a sodium sulphite solution to absorb SO_2 from a gas stream. In the treatment of Claus plant tail gas using the W-L process, the tail gas is first incinerated to convert all sulphur compounds present to SO_2. The gas is then cooled in a waste heat boiler and by water quench to remove water vapour. The cooled gas stream is contacted with sodium sulphite which absorbs almost all of the SO_2. Process gas exiting the absorber contains less than 250 ppm of SO_2. The loaded solution from the SO_2 absorber is passed through an evaporator-crystallizer where the SO_2 is released and

sodium sulphite crystals are precipitated. The crystals are dissolved in water and the resulting solution is circulated back to the SO_2 absorber. SO_2 released from the evaporator-crystallizer is returned to the Claus plant for processing.

The process is designed to increase sulphur recovery levels to 99.95 per cent.

There are 8 commercial-scale installations of the W-L process treating Claus plant tail gas, the largest being a 300 t/d plant.

Capital costs of the W-L process range from 130 per cent of a large 2-stage Claus plant to 200 per cent of a smaller (50 t/d) 2-stage Claus plant.

- Citrate

In the Citrate process, Claus tail gas is incinerated to oxidize all remaining sulphur compounds to SO_2. The gas stream is then cooled by a water quench and contacted with lean Citrate solution which absorbs the SO_2. Vent gas from the SO_2 absorber contains only a small amount of SO_2 and is heated and discharged to atmosphere. A stream of acid gas (H_2S/CO_2) is by-passed around the Claus plant to the Citrate tail gas clean-up unit to be contacted with the SO_2-rich Citrate solution. H_2S and SO_2 react to produce solid particles of sulphur. Excess H_2S is provided to ensure complete regeneration of the Citrate solution. Off-gas from the regeneration step is incinerated to oxidize remaining H_2S to SO_2. This is then returned to the SO_2 absorption stage. Produced sulphur is in the form of small crystals (5 to 15 microns in size) suspended in the Citrate solution. The solution flows to a flotation tank where air is bubbled through the solution to float the sulphur particles to a froth on the surface. The froth is removed and heated to melt the sulphur for separation from the Citrate solution.

In the process, a side reaction produces sulphuric acid which is neutralized by the addition of sodium hydroxide. A product of the neutralizing reaction is sodium sulphate which is purged from the system and through an evaporative cooling step produces by-product Glauber's salt crystals.

The process is designed to recover 95 to 99 per cent of the SO_2 in the feed to the unit.

One commercial-scale application has been built to treat flue gas from a coal-fired boiler. There have been no commercial installations in the gas processing industry.

No capital and operating cost information is available for the Citrate process.

- ATS (Ammonium Thiosulphate)

The first step of the ATS process is the incineration of Claus tail gas to oxidize all sulphur compounds to SO_2. The hot gas is then cooled by a water quench and contacted with an aqueous ammonium solution. SO_2 reacts to produce ammonium sulphite and ammonium bisulphite. The ammonium sulphite/bisulphite solution is mixed with a stream of acid gas feed by-passed from the Claus plant. H_2S reacts with the solution to produce ammonium thiosulphite. The ammonium thiosulphite solution is then concentrated to a 60 weight per cent solution by evaporating water. The solution is then stored for sale as fertilizer. Because ammonia is consumed in this process in producing ammonium thiosulphite, it is necessary to have a source of ammonia as well as a market for the fertilizer product.

The process is designed to reduce the SO_2 content in treated Claus tail gas to less than 250 ppm.

There are three commercial installations of the ATS process.

The capital cost of the ATS process is approximately 70 to 100 per cent of an associated 2-stage Claus plant. The economics of ATS are largely dependent on an ammonia source and markets for the ammonia thiosulphate product.

- Pritchard CleanAir

In the CleanAir process, Claus tail gas is contacted with a water stream which absorbs essentially all of the SO_2 present in the gas. A slipstream of acid gas feed to the Claus plant is diverted to a second absorber in the CleanAir unit where it is contacted with water into which H_2S is absorbed. This acid gas stream leaving the H_2S-absorber is returned to the Claus plant. The SO_2-rich stream is mixed with the H_2S-rich stream in a reaction tank where the Claus reaction proceeds to produce solid-phase sulphur. Sulphur produced in the reaction tank flows as a sulphur/water slurry to a floculator vessel where it settles and is drawn off the bottom to be melted. The Claus tail gas exiting the SO_2 absorber has had all of the SO_2 removed but still contains H_2S. This stream is contacted with Stretford solution and essentially all of the H_2S is converted to sulphur.

In order to minimize the sulphur compounds remaining in the treated tail gas from the CleanAir process, it is necessary to minimize the COS and CS_2 fed to the unit from the Claus plant. It is possible to

reduce the content of remaining sulphur compounds in the CleanAir off-gas to less than 250 ppm and achieve an overall sulphur recovery level of 99.9 per cent on a design basis.

The process has been developed to the commercial-scale design stage but has not yet been demonstrated in a commercial application.

No capital or operating cost information is available for the CleanAir process.

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